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ELECTRIC POWER WHEELING AND DEALING:
Technological Considerations for Increasing Competition

VOLUME II -- CONTRACTOR DOCUMENTS
Part D

1. Survey of Utilities' Reactions to Increased Competition

2. Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States

These Contractor Documents were prepared by outside contractors as an input to an OTA assessment. They do not necessarily reflect the analytical findings of OTA, the Advisory Panel, or the Technology Assessment Board.

J952-61

SURVEY OF UTILITIES' REACTIONS TO INCREASED COMPETITION

Conducted by the Office of Technology Assessment

September 1988

OTA is grateful for the time and effort spent by participating utilities. The results of this survey express the views of the cooperating utilities and not necessarily those of OTA. This document has not been reviewed or approved by the Technology Assessment Board.

As part of its assessment **Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition**, OTA surveyed a number of utilities in an effort to determine reactions to change the industry's competitive environment. OTA sent questionnaires to 28 utilities, including IOU's, cooperatives, municipals, and federal marketing agencies. Twenty-three utilities responded. The questionnaire was intended to supplement the extensive interviews OTA had with several utilities in early 1988.

In order to maintain the utilities' confidentiality, responses to questions 1-7, 13-14, and 17-18 have been omitted from the survey report. Instead, OTA has summarized the responses to these questions. Responses to the remaining questions are provided, except where confidentiality could not be maintained.

Copies of the questionnaire, cover letter, and summary of the scenarios are included.

June 9, 1988

Dear

In recent years there have been many proposals intended to increase competitiveness in the electric utility industry. The Office of Technology Assessment has been asked by the House Committee on Energy and Commerce to analyze the technical feasibility and implications of these proposals. We are asking for your help in this analysis.

Specifically, we would like to know how your utility would react if certain steps are implemented. We have created five policy scenarios to represent the range of proposals that have been suggested. These scenarios range from minor adjustments in the existing regulations to radical changes in the industry's structure. They are described in detail in the attachment. The enclosed questionnaire solicits your utility's sense of the impact these changes would have and how you would adapt.

This survey supplements the intensive interviews we have had with several utilities. Some of the questions will be difficult to answer, but I hope you will find it worthwhile to spend the time on them. As you know, things are changing rapidly in the industry, and it is important for the Congress to understand the full complexity of the situation if they act to guide these changes. This is a chance for you to provide important input to this process.

Your answers will be held in strict confidence and will not be identified in any OTA reports or testimony, although we will credit those who assist us unless you request otherwise. In order for us to incorporate your responses, we request that you return the survey by early to mid July. If you have any questions or comments, please call me or Robin Roy at (202) 228-6260.

We greatly appreciate your assistance. We will be happy to send you the final report when it is ready, as well as the results of this survey and a contractor report we commissioned on several case study responses to the scenarios.

Very truly yours,

Alan T. Crane
Project Director

Attachments (2

OFFICE OF TECHNOLOGY ASSESSMENT

QUESTIONAIRE ON
POWER INDUSTRY COMPETITION

Utility Name:_____
Contact for Follow-Up:_____
Telephone Number:_____

General

1. Anticipated peak demand (MW)
   Summer: 1988:_____; 1996:_____.
   Winter: 1988:_____; 1996:_____.

2. Anticipated annual net energy for load (GWH) 1988:_____; 1996:_____.

3. Utility-Owned capacity (MW) 1988:_____; 1996:_____.

4. Anticipated purchases (or sales) of capacity and energy from other utilities through power pools or other arrangements:

   Capacity at time of peak (MW)
   Summer: 1988:_____; 1996:_____.
   Winter: 1988:_____; 1996:_____.

   Net Annual Energy (GWH) 1988:_____; 1996:_____.

5. Please list any utility generation construction projects, including significant plant upgrades and plant life extension projects currently ongoing or planned to begin by 1996.

Unit Name	MW*	Primary Fuel	Unit Type	Start Date	Completion Date

* Net Dependable Capability Added or Changed.

6. Please list any new transmission circuits or significant transmission upgrades under construction or planned to begin by 1996. For upgrades, please give the type of upgrade (e.g. increase in voltage, restringing, etc.)

Name/ location	kV*	Miles	Purpose/ Type	Start Date	Completion Date

* Note if operating voltage different than design voltage.

7. Do you operate your own control area? If not, in which control area do you operate? If so, do you perform control area services for any other utilities (e.g., full or partial requirements munis)?

8. How frequently or under what conditions do you recalculate economic dispatch, unit commitment, and maintenance schedules?

9. Do you have transmission or security constraints which require scheduling generation "off-economy" or restrict additional bulk power sales or purchases? If the constraints were eased, to what extent would operating economics improve or bulk power transactions increase?

10. What reliability standards do you currently use (e.g., 1 day in 10 years loss of load probability, first contingency stability)? Have you performed studies quantifying the value of reliability to your customers? If so, how are these studies used in setting reliability goals?

"Rolling Prudence Reviews" of New Construction

OTA's Scenario 1 includes a process for prior state regulatory approval of new construction projects with periodic prudency reviews during construction to reduce the regulatory risk for new plants and to allow utilities to attract needed capital.

11. Under present conditions, do you consider construction of new capacity to be a high financial risk? If so, why?

_____

_____

_____

12. Would a process of prior and periodic regulatory approval ("rolling prudence") adequately address any concerns over investing in new capacity? How would rolling prudence alter your utility's capacity expansion plans as indicated in question five (e.g., different fuels, baseload vs. peaking, unit size)?

_____

_____

_____

Accomodating Non-Utility Generators and Competitive Generation

Non-utility generators (NUGs) include Independent Power Producers (IPPs) and PURPA Qualifying Facilities (QFs).

13. How much NUG capacity and energy do you anticipate in your service area (MW and GWH) assuming no change in present policy?

		MW* / GWH		MW* / GWH
IPPs	1988:	_____/_____;	1996:	_____/_____.
PURPA QFs	1988:	_____/_____;	1996:	_____/_____.

* At time of peak.

14. How much on-site self-generation do you anticipate?

	MW* / GWH		MW* / GWH
1988:	_____/_____;	1996:	_____/_____.

* At time of peak.

15. How does the size, cost, fuel use, availability and reliability of NUG power compare with that of the plants that your utility has now or would consider building?

_____

_____

_____

16. What planning and operating difficulties, if any, have you encountered to date with integrating NUGs into your system?

_____

_____

_____

17. Do NUGs on your system contribute to:

	All	Some	None
a. frequency regulation using speed governors?	( )	( )	( )
b. voltage regulation using reactive power output?	( )	( )	( )

18. Does your utility have control of NUGs:

	All	Some	None
a. for economic dispatch?	( )	( )	( )
b. for security dispatch?	( )	( )	( )
c. for unit commitment?	( )	( )	( )
d. for maintenance scheduling?	( )	( )	( )
e. during system emergencies and restoration?	( )	( )	( )

19. Under what circumstances (e.g., % installed capacity, size of individual NUGs, locations) would a lack of the characteristics listed in questions 17 and 18 significantly impact system reliability and cost, requiring major changes to your planning and operations?

_____

_____

_____

20. Can you accurately calculate the reliability and economic impacts of having less central coordination of the characteristics listed in questions 17 and 18? What models and engineering expertise are required?

_____

_____

_____

21. OTA's Scenario 3 includes all source competition for new bulk electricity supplies with market-based pricing. If competitive bidding were adopted for new power supplies with utilities determining the needs and preferred locations and sources, would your utility want to compete in the bidding for its own needs? Would your utility want to compete to supply generation in other utility service areas?

22. OTA's Scenarios 4 and 5 entail substantially restructuring the power industry by segregating a competitive generating sector from transmission and distribution. What operating and planning problems would have to be solved before the utility could split generation from transmission and distribution? For instance, what would have to be in contracts between generation and transmission companies to ensure that dispatch would operate as reliably and economically as it does now?

Increased Wheeling

OTA's scenarios 2 through 5 provide for a variety of wheeling arrangements. A wide variety of wheeling arrangements can be developed, depending on a) who generates the electricity (e.g., another utility, a NUG); b) who purchases the electricity (e.g., a neighboring utility operating in its own control area, a full or partial requirements utility within your control area, a retail customer); c) the terms of the transfer (e.g., how long in advance the transfer is scheduled and how often the schedule changes, interruptibility of transfer).

Each type of wheeling may have different impacts on a utility's ability to regulate voltage and frequency, and reliably and economically schedule and dispatch generation.

23. Is there a significant difference in technical feasibility between wheeling power generated by a) another utility; and b) an IPP or QF? If so, what are the differences?

24. Is there a significant difference in technical feasibility between: a) wheeling for retail customers; b) wheeling for whole or partial requirements utilities within your control area; and c) wheeling for utilities outside your control area? What are the differences?

25. How would utility planning and operations change if wheeling for retail customers, requirements customers, or other integrated utilities were made mandatory or strongly encouraged?

26. What changes to your system would be necessary to reliably and economically accommodate additional wheeling?

27. Can you accurately calculate the reliability and economic impacts of having less central coordination of the characteristics listed in questions 17 and 18 as a result of increased wheeling? What models and engineering expertise are required?

GENERAL COMPARISON OF ALTERNATE SCENARIOS

28. Please compare (as quantitatively as possible) all five scenarios for their impact on cost, reliablity, and quality of service.

DRAFT
ALTERNATIVE SCENARIOS
FOR INCREASING COMPETITION IN THE ELECTRIC POWER INDUSTRY

FOR USE IN OTA'S ANALYSIS OF TECHNICAL REQUIREMENTS AND LIMITATIONS FOR INCREASED BULK POWER TRANSFERS AND WHEELING

Scenario 1

Strengthening the Existing Regulatory-Utility Bargain

Scenario 1 continues the existing regulatory scheme and electric power industry structure and reaffirms the regulatory-utility bargain with minor modifications of regulatory rules and procedures to improve the ability of utilities to attract capital for construction of new facilities and to assure a reasonable return to investors (e.g., "rolling prudence reviews"). Modifications of PURPA rules to correct perceived imbalances in avoided cost pricing rules for QF power would also be allowed. Many utilitities will continue to rely on QFs and IPP's for a portion of new power needs. Transmission access would remain on a voluntary basis to be negotiated between the participants. FERC would retain its authority over transmission rates and wholesale power sales.

Industry structure: A mix of vertically-integrated utilities, investor-owned utilities, public power, cooperatives, and Federal power authorities, self-generators, qualifying facilities (QF's), and independent power producers (IPP's). Trends of internal realignments and restructurings and mergers and acquisitions continue within limits of existing laws.

Regulatory structure: Existing Federal and State regulatory scheme. No changes in PURPA, FPA, PUHCA. Minor modifications/adjustments to rules as noted above.

Transmission Access: Utilities may provide access voluntarily for wholesale and retail customers. (No new NRC wheeling orders as part of new nuclear plant approvals are likely - no new nuclear plants; stringent standards for FERC wheeling orders also likely to preclude mandatory wheeling; States have limited jurisdiction.)

System Operation:

System reliability and coordination is maintained by the local utility/control center. For non-utility power supplies, operational responsibilities are based on contract terms with the local utility.

Dispatch (maintenance, unit loading) is determined by the local utility (perhaps under a power pool agreement) for utility owned or leased units. For QFs and IPPs, dispatch depends on contract terms with local utility.

Emergency curtailments are allocated according to state regulated curtailment policies.

Planning and Developing Resource Additions:

Generating capacity: Utilities develop capacity expansion plans with state regulatory oversight. QFs are assured market for their power under the state's implementation of PURPA and are a component of the expansion plan. IPPs may be included in the expansion plan as determined by the utility and state regulators. QFs, IPPs and self-generators plan and build capacity based on their own perceptions of need and profitability.

Transmission additions are developed by local utilities subject to regulatory approval. Some non-utility entities may build private transmission lines, but have no eminent domain authority and uncertain regulatory status.

Distribution additions are the responsibility of local utilities with regulatory approval.

Conservation and load management programs are developed by local utilities with regulatory approval.

Pricing:

Prices are set by utilities in regulatory proceedings. Most retail services are bundled, but states allow utilities to offer special rates based on different reliablility levels and services to large retail customers in response to competitive pressures. Transmission prices are regulated by FERC. States have limited jurisdiction over transmission.

Scenario 2

Expanding Transmission Access in the Existing Institutional Structure

Scenario 2 is intended to increase both the number of bulk power sellers and the number of potential bulk power buyers by 1) removing some of the size, technology, fuel, and ownership limitations for qualifying facilities through legislative modifications to PURPA and the Public Utility Holding Company Act; and 2) changing the mandatory transmission access provisions of the Federal Power Act to a broader public interest standard to make utilities and large retail customers eligible to apply for mandatory wheeling orders. Policies intended to encourage bulk power sales and wheeling will be continued and expanded.

Industry structure: Existing mix of utilities, self-generators, co-generators, independent power producers; unregulated utility subsidaries/affiliates will increase participation in bulk power supply; current trends of restructuring, mergers and acquisitions continue.

Regulatory structure: Existing Federal-State regulatory scheme with wider eligibility for QF's under PURPA and broader FERC authority for issuing mandatory wheeling orders for utilities and large retail customers.

Transmission access: Utilities and large retail customers can petition FERC for mandatory wheeling orders to nonlocal generators based on a new public interest standard.

System Operation:

System reliability and coordination is maintained as in Scenario 1.

Dispatch (maintenance, unit loading) are the same as in Scenario 1, with the following exception. For transmission accessors not subject to utility control, loading and dispatchability are determined by contracts between generator and consumer.

Emergency curtailments are allocated according to state regulated curtailment policies. (Same as in scenario 1). For outages of nonutility wheeled power, curtailment and backup power are based on standby service contract with local utility.

Planning and Developing Resource Additions:

Generating capacity: Same as in Scenario 1, with one addition. IPPs (as well as QFs) are assured a market for their power under the state's implementation of PURPA and are a component of the capacity expansion plan.

Transmission additions: Same as in Scenario 1, with the following exception. States may require that utilities include provisions for adequate transmission capacity for wheeling services in system planning.

Distribution additions: Same as in Scenario 1.

Conservation and load management: Same as Scenario 1.

Pricing:

The existing structure of price and service regulation is largely left undisturbed. Prices paid to power suppliers under PURPA are based on states' avoided cost rules (includes use of bidding systems by some states). Transmission services/pricing are established by contract negotiation under FERC jurisdiction.

Scenario 3

Competition for New Bulk Power Supplies

Scenario 3 establishes an institutional structure to allow all source competition for new bulk power supplies with market based pricing. The scenario is loosely based on the Keystone and Hesse proposals. Transmission access is included as a prerequisite for participation in the competitive system. Mandatory transmission access under the public interest standard of Scenario 2 is also available for bulk power transactions by utilities. Provision of wheeling services to retail customers remains voluntary. Utilities are able to participate in "bidding" for new capacity within their own service territories and those of other utilities with appropriate safeguards to limit problems of self-dealing, conflict of interest, etc. Scenario 3 creates a two-tiered bulk power supply system: new power supplies under a minimally regulated, "workably-competitive" market; and existing generation remaining under current state-federal scheme of regulated entry and pricing. The electric power supply industry will gradually evolve to an all competitive generating sector as existing plants are replaced. Transmission and distribution services remain highly regulated.

Industry structure: Existing mix of utilities, self-generators, co-generators, independent power producers is expanded by entry of unregulated utility subsidiaries/divisions/spinoffs created to build and operate new generating facilities and to sell power in competitive market and other new entrants made eligible by modification of PURPA QF requirements and changes to PUHCA.

Regulatory structure: Underlying Federal-State public utility regulatory scheme is maintained but entry and pricing regulation for new power supplies is replaced by all source competition. Generating sector gradually is transformed to all competitive system as existing capacity is phased out. Transmission and distribution remain highly regulated.

Transmission access: Three mechanisms exist for provision of transmission services: 1) voluntary transmission agreements for utilities and retail customers; 2) transmission access for new power supplies is assured as a precondition for utility participation in the competitive "bidding" system; and 3) mandatory "public interest" transmission orders are available from FERC for utilities, but not for retail customers.

System Operation:

System reliability and coordination is maintained as in Scenarios 1 and 2.

Dispatch (maintenance, unit loading) is the same as in Scenario 2.

Emergency curtailments are the same as in Scenario 2.

Planning and Developing Resource Additions:

Generating capacity: Same as in Scenario 2 with the following exception. The states' are required to use competitive bidding including consideration of non-price factors in selecting new power supplies.

Transmission additions: Similar to Scenario 2, the public utility transmission company/division plans and constructs transmission capacity with review and approval of regulatory authorities. State rules may require utilities to plan for

adequate capacity for instate wheeling of new power supplies and to consider regional transmission needs.

Distribution additions: Same as in Scenario 2.

Conservation and load management: Same as in Scenarios 1 and 2.

Pricing:

"Old" power supplies remain under existing price regulation. Prices for new power supplies are market based - set by competitive auction or negotiation. New power supply prices can reflect level of service and other non-price factors. Greater reliance on transmission services may increase pressure for transmission pricing based on actual cost of service with allowances for non-price factors. Transmission prices are regulated by FERC.

Scenario 4

All Source Competition for All Bulk Power Supplies with Generation Segregated from Transmission and Distribution Services

Scenario 4 would create a competitive system for electric power supplies. Existing and new sources would compete to sell power to regulated transmission and/or distribution companies. Integrated utilities would be required to segregate generation activities both institutionally and operationally from transmission and distribution - through creation of separate divisions, subsidiaries or spinoffs. Transmission and distribution activities would be heavily regulated. Modifications to PURPA QF requirements and PUHCA restrictions allow broad participation in generation markets. Local distribution companies would be primarily responsible for securing adequate power supplies from competing suppliers. Transmission divisions or subsidiaries companies would provide wheeling services for utilities under regulated rate schedules and could also act as power brokers linking local distribution companies with power suppliers. Distribution companies could obtain mandatory transmission orders could be obtained from FERC on a public interest standard. There would be no mandatory wheeling for retail customers, however it is expected that generators and transmission companies would engage in direct sales to large retail customers on a voluntary basis with bypass or standby payments to local distribution companies.

Industry structure: Vertical integration of industry is reduced by separation of utility generating segments from transmission and distribution segments. Segregated utility generators, QF's, and IPP's compete to provide power supplies to transmission - distribution and local distribution companies. Some transmission companies also act as power brokers. Industry structure is similar to that of natural gas industry.

Regulatory structure: Price and entry regulation for electric power supply is replaced with competitive market. State regulation of distribution companies and retail sales. Mixed federal-state regulation of transmission capacity and services. Under this scenario there is the potential for increased Federal regulation and oversight of power sales and formerly intrasystem transmission arrangements, however, implementing legislation could provide for a more balanced Federal-State division of regulatory authority to give states greater control over intra-state activities.

Transmission access: With FERC endorsement, States condition nondiscriminatory access to transmission services as precondition for existing regulated generation, transmission, and distribution companies to participate in new competitive system. FERC has authority to order wheeling for customer utilities on a public interest standard. Transmission access for retail customers is provided on a voluntary basis.

System Operation:

System reliabilty and coordination is maintained by the regulated transmission company or transmission-distribution company. Operational responsibilities of power suppliers and the local distribution companies are specified in contracts.

Dispatch (maintenance, unit loading) are determined by various contracts between power suppliers and either: 1) the regulated transmission companies; 2) the regulated distribution companies; or 3) retail customers.

Emergency curtailments for retail customers served by local distribution companies are allocated according to state regulated curtailment policies. For other customers, curtailments are specified in contracts with the transmission and generation suppliers.

Planning and Developing Resource Additions:

Generating capacity: Electric supply requirements are determined through local distribution company planning processes with state oversight. Competition for supply contracts is open to all generating sources, as in Scenario 3. Transmission utilities may contract for generating capacity to allow them to serve as power brokers subject to state and federal regulation.

Transmission additions: The regulated transmission or transmission-distribution companies have the obligation to provide transmission capacity necessary to support wheeling needs for instate utilities. States may require transmission capacity planning to include consideration and coordination of regional transmission system needs.

Distribution additions: Same as in Scenario 3.

Conservation and load management: Conservation and load management programs are provided by local distribution companies, possibly in conjunction with transmission companies.

Pricing:

Bulk power sales are set through competitive markets. Transmission services are regulated by state and federal authorities. Power purchases by distribution companies and retail rates are regulated as now by state authorities.

Scenario 5

Common Carrier Transmission Services in a Disaggregated, Market-Oriented Electric Power Industry.

The electric power industry is divided into institutionally separate generation, transmission, and retail distribution segments. The major difference between this scenario and scenario 4 is that separate transmission companies would explicitly be required to provide transmission services as a common carrier - i.e. non-discriminatory service based on approved wheeling tariffs - to all parties requesting service. The transmission company would have an obligation to provide adequate transmission capacity. Retail customers would have access to transmission services. Distribution and transmission services would remain tightly regulated, but in the electric generation segment, market entry and bulk power pricing would primarily be left to market forces. Federal and state policies might encourage greater aggregation in transmission services to create coordinated large regional transmission systems - either through mergers and acquisitions or through operational agreements among neighboring systems.

Industry structure: Competitive generation segment includes formerly regulated utility generation operations, QF's, and IPP's. Regulated transmission systems are operated as common carriers. Regulated local distribution companies provide retail services.

Regulatory structure: Generation segment subject to minimal regulation to assure existence of workably competitive markets. Transmission segment regulated as a common carrier by Federal and State governments. Local distribution companies regulated by state authorities.

Transmission access: Common carrier transmission access - services available on non-discriminatory basis to wholesale and retail customers. Wheeling customers could contract for different levels of service.

System Operation:

System reliability and coordination is maintained by the separate, regulated transmission company. Operational responsibilities of power suppliers and the local distribution are specified by contracts between them and the transmission company.

Dispatch (maintenance, unit loading) is determined as in Scenario 4.

Emergency curtailments is allocated as in Scenario 4.

Planning and Developing Resource Additions:

Generating capacity: Same as in Scenario 4.

Transmission additions: The transmission utility has an obligation to provide an adequate and reliable transmission capacity necessary to supply the wheeling needs of anticipated customers. (Regulatory authorities may require consideration/coordination of regional transmission capacity needs.)

Distribution additions: Same as in Scenario 4.

Conservation and load management: Same as in Scenario 4.

Pricing:

Bulk power sales are set through competitive markets. Transmission services are regulated by state and federal authorities on common carrier basis. Transmission rates include adequate signals to assure construction of new transmission facilities. Power purchases by distribution companies and retail rates are regulated as now by state authorities.

* * *

QUESTION 1. ANTICIPATED PEAK DEMAND (MW)?

The surveyed utilities' 1988 summer peak demand ranged from a low of about 200 MW to a high of 20,200 MW. Four utilities had summer peak demands of 15,000 MW or more, and five peaked at 2,500 MW or less. About two-thirds of the surveyed utilities were summer peaking in 1988. One additional utility crossed over from winter to summer peaking in 1996.

QUESTION 2. ANTICIPATED ANNUAL NET ENERGY FOR LOAD (GWH)?

Anticipated demand ranged from a low of 800 GWH to a high of 111,000 GWH in 1988. Ten utilities indicated that 1996 demand would be 20 percent or more higher than 1988 figures. Only four utilities reported that 1996 demand would not increase by more than 10 percent from 1988 figures.

QUESTION 3. UTILITY-OWNED CAPACITY (MW)?

Surveyed utility-owned capacity ranged from 240 MW to 29,500 MW in 1988. Nine respondents showed no increase in utility-owned capacity in 1996. The addition of about 4,400 MW was the largest increase among the surveyed utilities.

QUESTION 4. ANTICIPATED PURCHASES (OR SALES) OF CAPACITY AND ENERGY FROM OTHER UTILITIES THROUGH POWER POOLS OR OTHER ARRANGEMENTS?

A majority of respondents anticipated purchasing capacity, and only six expected to sell power in 1988. Two utilities did not expect to be involved in power transfers.

QUESTION 5. LIST ANY UTILITY GENERATION CONSTRUCTION PROJECTS, INCLUDING SIGNIFICANT PLANT UPGRADES AND PLANT LIFE EXTENSION PROJECTS CURRENTLY ONGOING OR PLANNED TO BEGIN BY 1996?

QUESTION 6. LIST ANY NEW TRANSMISSION CIRCUITS OR UPGRADES UNDER CONSTRUCTION OR PLANNED TO BEGIN BY 1996?

Seven of the twenty-three responsents had no ongoing and/or planned generation construction projects. All but three of the respondents had new transmission circuits and/or significant upgrades under construction or planned to begin by 1996.

QUESTION 7. DO YOU OPERATE YOUR OWN CONTROL AREA? IF SO, DO YOU PERFORM CONTROL AREA SERVICES FOR ANY OTHER UTILITIES?

A majority of respondents operate their own control area. About half of the surveyed utilities indicated that they provide control area services for other utilities.

QUESTION 13. HOW MUCH NUG CAPACITY AND ENERGY DO YOU ANTICIPATE IN YOUR SERVICE AREA ASSUMING NO CHANGE IN PRESENT POLICY?

Fourteen respondents indicated that they had QF capacity. QF capacity ranged from 2 MW to 1,537 MW. The remainder reported no QF capacity. Only one utility expected to have 110 MW of IPP capacity in 1988. The total 1988 QF/IPP capacity reported by the respondents was about 3,300 MW.

Fifteen utilities expected to have some QF capacity in 1996, the largest capacity anticipated by a utility was 1,235. The total 1996 QF/IPP capacity increased by 1,300 MW from 1988 figures.

QUESTION 14. HOW MUCH ONSITE SELF-GENERATION DO YOU ANTICIPATE?

A majority of respondents expected to have some onsite self-generation in 1988. The amount, however, varied considerably from 1 MW to 770 MW. In 1988, respondents' onsite generation totalled 2,315 MW and increased to 2,954 MW in 1996.

QUESTION 17. DO NUGS ON YOUR SYSTEM CONTRIBUTE TO FREQUENCY AND VOLTAGE REGULATION?

About three-fourths of the surveyed utilities indicated that NUGS do not contribute to frequency regulation. And, about 60 percent reported that NUGs do not contribute to voltage regulation.

QUESTION 18. DOES YOUR UTILITY HAVE CONTROL OF NUGS FOR ECONOMIC DISPATCH, SECURITY DISPATCH, UNIT COMMITMENT, MAITENANCE SCHEDULING, AND DURING SYSTEM EMERGENCIES AND RESTORATION?

Almost all of the respondents indicated that they had no control of NUGS for economic dispatch and unit commitment. Two-thirds noted that they had no control for security dispatch. But, about one-half of the surveyed utilities indicated that they had at least some control for maintenance scheduling and during system emergencies and restoration.

QUESTION 8

HOW FREQUENTLY OR UNDER WHAT CONDITIONS DO YOU RECALCULATE ECONOMIC DISPATCH, UNIT COMMITMENT, AND MAINTENANCE SCHEDULES?

Economic Dispatch every six seconds.

Unit Commitment Daily

Maintenance schedules are revised on an on-going basis.

Economic dispatch is currently calculated every 90 seconds. Unit commitment is performed at least once per day, and revised as needed.

Maintenance schedules are prepared on an annual basis and revised periodically.

8.

Economic Dispatch

Utilizing Energy Management System (EMS), full economic dispatch of on-line controllable units occurs every five minutes. Approximate economic dispatch occurs every four seconds. Units which are not controlled by the EMS are manually loaded as needed to meet system requirements as economically as possible.

Unit Commitment

Operating personnel make unit commitment decisions as much as two years in advance for budget purposes. Dispatching personnel make unit commitment decisions on an on-going hour-by-hour basis as needed. Additional unit commitment planning occurs on a monthly, weekly, and daily basis by operations support personnel.

Maintenance Schedules

Maintenance schedules are developed several years in advance of the actual outages. Schedules for large multi-participant resources are modified annually as necessary. A weekly update of the maintenance schedule includes changes which have taken place since the last weekly update. Dispatching personnel also grant outages on a daily basis which may or may not be included in the weekly maintenance schedule.

Economic dispatch conducted by . , only economic dispatch modelling "in house" is for power supply studies. Maintenance schedules are recalculated annually by joint and . . agreement; updates are established as needed.

Economic dispatch is recalculated at least every five minutes. Fuel prices are reviewed monthly and heat rates are revised as new ones become available. Unit commitment is reviewed or recalculated daily or more frequently if conditions require. Maintenance schedules are reviewed monthly and changed if conditions dictate.

Economic dispatch is recalculated approximately every five minutes or when there is a significant system generation change. Unit commitment is normally recalculated twice daily or when there is a significant system generation or load change. Maintenance schedules are developed on a yearly basis and are changed on an as needed basis.

Generally monthly.

automated economic dispatch recalculates basepoints every five minutes. generation is coordinated with but not under the direct control of utomated dispatch. All member systems continually coordinate maintenance schedules of generation and transmission facilit

8.
Economic dispatch is calculated every 60 seconds or whenever the change in system load exceeds a threshold limit. Unit commitment is determined daily. The maintenance schedule is planned annually and updated as necessary.

Hydro generation has historically provided the most economical bulk power rates in the western states. National and state water release criteria and power plant annual maintenance scheduled by the Federal plant operating agencies have the greatest influence on the dispatch of the Federal hydro system resources. This Federal hydro and transmission system are utilized, to the extent practical, in scheduling economic dispatch of the control areas thermal units. The Federal system is also utilized, when available, to provide emergency and scheduled service during maintenance outage on thermal units.

Formal maintenance schedules are revised periodically, weekly if necessary, to reflect changes in maintenan system operating requirements, and other factors. maintenance conditions are under continual review communication and coordination between the generating f system control centers.

Response:

In order to provide the lowest cost power achievable in response to customer demand, computerized recalculation of economic dispatch is done at least every 10 minutes as part of system operation and control functions.

Unit commitment is under continual review as part of routine system control functions. This is necessary to insure adequate power supplies. Computer analysis of unit commitment is run four or more times per week as necessary.

8. The Control Center recalculates economic dispatch every 14 seconds; unit commitment at least daily and up to 5 times daily as required, and updates maintenance schedules monthly.

Economic dispatch is done by computer, continuously. Unit commitment is performed once each day under normal circumstances. Maintenance schedules are revised as dictated by load, operating, and equipment performance.

Economic dispatch is recalculated every 3 seconds. Unit commitment is redetermined several times daily. Maintenance schedules are developed monthly.

Economic dispatch: 4 seconds

Unit Commitment: daily

Maintenance Schedules: semiannually

Economic Dispatch -- every 5 minutes or on demand

Unit Commitment -- on demand as required

Maintenance Schedules -- for major changes due to unexpected outages

Economic dispatch is recalculated continuously, unit commitment schedules are developed daily and maintenance schedules are reviewed weekly.

Normal economic dispatch and unit commitment are done by We prepare the maintenance schedules on our 100%-owned units. Maintenance schedules for are prepared by the operating owner.

Economic dispatch - every two seconds

Unit commitment - daily

Maintenance Scheduling - daily, weekly, monthly, seasonal

Economic Dispatch is recalculated hourly. Unit commitment is recalculated daily and reviewed hourly. Planned maintenance schedules are developed annually and reviewed as needed.

Daily unless sales opportunity or change in status of generation equipment requires an update.

Economic Dispatch: is one of the four electric operating companies within the and continuously operates in a pool economic dispatch arrangement with the other three operating companies. Economic dispatch is performed every four seconds by the Central Control Center and the resulting dynamic interchange schedules are transmitted to the operating companies over high speed, computer-to-computer data links. Each of the operating companies, including , economically controls their own generation resources to meet these interchange schedules.

Should the Central Control Center computer or the high speed data links be out of services, the economic dispatch computer performs economic dispatch every three minutes, with generation controlled every four seconds to meet demand changes. Should any system parameters that effect economic dispatch, such as fuel prices, unit limits or unit status, change during the normal three minute interval, then economic dispatch is recalculated.

Unit Commitment: Currently, performs a unit commitment each day under normal operating conditions. Should the committed generation status change because of maintenance, forced outage, or emergencies, the unit commitment is reevaluated as needed.

Maintenance Schedules: prepares a five year generation maintenance schedule. This five year planned maintenance schedule is coordinated with the Central Control Center and in-turn the other three operating companies. The current year of the maintenance schedule is updated at least weekly, or as the need arises, with both the Central Control Center and the security centers. The ERCOT security centers in-turn coordinated the maintenance schedule with all the other control areas in

Economic Dispatch is recalculated hourly. Unit commitment is recalculated daily and reviewed hourly. Planned maintenance schedules are developed annually and reviewed as needed.

Economic dispatch is recalculated every 4 seconds and when any generator parameter changes. Unit commitment is recalculated as required but a minimum of one time each day. The base maintenance schedule is developed annually and adjusted as needed.

Economic dispatch is recalculated every 2 to 4 seconds. Unit commitment is planned daily, revised as necessary. Maintenance schedules are done every year, adjusted as necessary.

QUESTION 9

DO YOU HAVE TRANSMISSION OR SECURITY CONSTRAINTS WHICH REQUIRE SCHEDULING GENERATION "OFF-ECONOMY" OR RESTRICT ADDITIONAL BULK POWER SALES OR PURCHASES? IF THE CONSTRAINTS WERE EASED, TO WHAT EXTENT WOULD OPERATING ECONOMICS IMPROVE OR BULK POWER TRANSACTIONS INCREASE?

Under almost all operating conditions there are no constraints which restrict bulk power transfers. Under some extreme conditions regional or state transfer limits can be approached and may limit power transfer to other utilities and/or states.

Yes. If constraints were eased there would be a minor net reduction in use of less economical generation, but no appreciable increase in bulk power transactions.

a) Generally no.

b) Transmission capacity with . is somewhat limited and occasionally precludes some economy transfers.

If constraints were eased, there would be a minor improvement in operating economics but certainly insufficient to pay carrying charges on required investment.

9. does not have such constraints but the Control Center schedules generation "off economy" when required by transfer limits on the PJM system and when imports from neighboring control areas are constrained by their transmission. The companies recently completed a transmission enhancement program costing $42 million to increase transfer capability. Additional capability (or further "easing" of constraints) would require major facility additions which cannot be economically justified. "Easing" the constraints by reducing reliability is unacceptable.

Yes, under some generation/transmission/load configurations on both a system and region basis. These constraints are infrequent; therefore, while there is an impact on operating economics and bulk power transactions when the constraints occur, the effect is minor and no major changes would be anticipated if constraints were eased.

Transmission constraints are experienced which, depending on their location in the network, require either scheduling generation "off economy" or restricting additional bulk power transactions. A detailed cost/benefit analysis must be performed for each specific reinforcement. Thus, it is not possible to generalize regarding the extent to which operating economies would improve or bulk power transactions would increase if constraints were eased.

No.

The transmission system is designed to accomodate planned net imports and exports while maintaining system security. Additional bulk power sales or purchases over those planned would reduce system reliability or require increased transmission system capability. Operating economics would depend on the balance between cost of service to customers and the cost of upgrading transmission capability.

No transmission contraints at this time.

Yes, transmission or security constraints do occur within [illegible]. If constraints were eased, economic benefits and transactions would increase but actual dollar and MW/MWHR benefits have not been determined.

9. Occasionally, the Colorado transmission system overloads and generation must be curtailed "off economy". (Both are coal fired generating stations in Colorado in which is a participant.) Sales of bulk power to northern California utilities are frequently restricted by transmission constraints. If constraints into the California market were eased, a significant quantity of coal-fired energy could be made available during off-peak hours.

Normally transmission/security constraints do not require loading units "off-economy."

There are constraints which require operating off optimum economy. The extent of improvement is difficult to quantify, but would improve.

has experienced, during transmission contingencies (outages), internal transmission limitations that required rescheduling of generation. Since these internal transmission limitations were only experienced occasionally, there would be no significant economic improvement if the internal transmission constraints were eased.

Yes. It is estimated that transactions would increase by approximately 1-2 percent.

No. With the current level of predicted growth, all equipment in service and the contractual method of power exchange, the system can withstand any reasonably foreseeable single contingency while operating economically.

No

9.
Yes, does have transmission constraints which require special operating considerations. Like many Western U.S. utilities has multiple load centers considerable distances apart. "Off-economic" operations do not offset the additional projected transmission expense required to match generation/load/area tie line contraints. The costs of "off-economic" operation do not offset the additional projected transmission expense required to operate "on-economics". Additions to the transmission system may facilitate additional bulk power transactions if such transmission additions affect external ties.

With all lines and units in service, the system is not constrained at peak or off-peak conditions.

The only way to "ease" the security constraints imposed on the power system by the minimum generation loading would be to construct an extensive bulk transmission system in addition to the existing transmission system. This bulk transmission system would eliminate the area security requirements, allow to run different generating units and to purchase additional off-system energy, assuming it was available. However, believes that this trade-off of transmission for generation would not be beneficial to our customers. In addition, believes that through prudent system planning, system operations, unit commitment, and economic dispatch that bulk power purchase transactions have been maximized to the extent possible.

supplies electric service to approximately retail customers in in an area of approximately square miles in the state of and has no transmission constraints under all normal and the majority of emergency operating conditions.

However, this is not the case for security constraints. Because of the large service area, there exists several security constraints on the generation requirements of the system. To ensure area security and adequate area voltage and reactive power support there are "must-run" generation facilities strategically located across the system. As a result of these "must-run" generators, there are times, particularly during daily off-peak periods, that generation cannot be decreased below minimum "security" loading requirements and at the same time provide area security.

In addition to the minimum loading requirement for "must-run" units, another generation constraint is the requirement to minimize the daily "cycling" of units during off-peak periods. is required by the and NERC Operating Guidelines to maintain adequate generation capacity during the on-peak periods to meet all the generation requirements for system demand and spinning reserve. However, to have this capacity on-line during the on-peak periods and not "cycle" units during the off-peak periods, increases the total minimum generation loading requirements on the system. It has been proven that daily "cycling" of generating units reduces the total life expectancy of a unit and contributes to increased maintenance costs.

has several security constraints which require scheduling generation off economy. If constraints were eased, operating economics would improve but not enough to justify system improvements at this time.

has experienced transmission constraints which resulted in purchasing power at higher rates than would otherwise be required for nonfirm power. Those same constraints limit . ability to provide transmission service requested by others. attempts to fully utilize its system to displace highest cost non-renewable generation with low-cost surplus generation. Unscheduled or "loop" flows on the Federal transmission system frequently severely limit ability to utilize the Federal system for its designed purposes. Phase shifting transformers are currently being installed to provide some relief from the existing loop flow conditions.

has no routine constraints. transmission transfer capability determines the size and number of transactions. NERC and scheduling guidelines are followed. To increase capability for more transactions would require new investment.

Response:

It is possible for economy purchases and sales with other interconnected utilities to be limited by the transmission capacity, both at the inter-connect points between utilities and across the operating system. Further, requirements that limit the economic dispatch of cogenerators have and could continue to force operation of the Company's generation "off economy".

Complete dispatch control of all generation sources by the operating utility could improve operating economy. Wheeling for economy transactions is presently being conducted with few transmission limitations. Additional wheeling, especially from a large number of sources to a dispersed group of users, could easily overload the existing transmission system. Because significant additions to the transmission system would be required, combined with the energy losses of the transmission system in additional wheeling transactions, it is unlikely that significant improvements in operating economics could be achieved. Extensive and detailed analysis would be necessary to determine what economies could be achieved, if any, by changes in the transmission system to effect a higher level of economy transactions.

QUESTION 10

WHAT RELIABILITY STANDARDS DO YOU CURRENTLY USE (E.G. 1 DAY IN 10 YEARS LOSS OF LOAD PROBABILITY, FIRST CONTINGENCY STABILITY)? HAVE YOU PERFORMED STUDIES QUANTIFYING THE VALUE OF RELIABILITY TO YOUR CUSTOMERS? IF SO, HOW ARE THESE STUDIES USED IN SETTING RELIABILITY GOALS?

For planning purposes, one day in 10 years loss of load probability is used as a general standard. has no studies quantifying the value of reliability to customers.

conducts first contingency reliability analysis and conforms to power pool reserve guidelines which are designed to meet the and the North American Electrical Reliability Council (NERC) requirements, where appropriate. has not independently conducted quantifying studies on the value of reliability.

10. utilizes an installed reserve criteria of 20%. plans to install generation equal to 120% of projected future peak loads for the purpose of successfully managing unforeseen events. has conducted studies to assess its generating system reliability using both the Loss of Load Probability (LOLP) and the Loss of Load Hours (LOLH) indices. A limited amount of study work addressing the value of reliability from the customer's perspective has been done. A current, major study effort will result in an assessment of projected generation system reliability in the context of our current reserve criteria.

LOLH, as calculated by EPRI's EGEAS model (assuming no tie-line capacity) is not permitted to exceed 235 hours. No studies quantifying the value of reliability to customers have been performed.

As a member of Mid-Continent Area Power Pool we use Pool standards in generation and transmission planning. We have not quantified the value of reliability to our customers.

uses an 18 percent planning reserve. Reliability studies sufficient to demonstrate a balance between availability and cost to customers are performed but do not assign a dollar value to reliability.

The adequacy criterion adopted by MAIN, regional reliability council, is an LOLP of .1 day per year or better, which is equivalent to 1 day in 10 years. EPRI and others are performing research in the area of customer outage costs and until such time as these costs can be estimated with greater certainty than available today, will rely on MAIN studies and be guided by the results of value of service evaluations.

Generating capacity requirements are based on a loss of load probability of 1 day in 10 years. Transmission requirements are based on analysis of single contingencies, contingencies involving loss of both circuits on a common structure and contingencies involving outage of a transmission facility and a "stuck breaker." Stability tests include three phase faults with primary clearing and single phase faults with back-up clearing. We have not performed studies quantifying the value of reliability to customers.

10. as do all members of the PJM Interconnection, plans its generation reserves for a one day in 10 years loss of load probability and plans and operates its system so that no single contingency will cause transmission loadings above emergency ratings or excessive voltage drops. These criteria are not based on quantitative studies.

10. is a member of the Southwest Power Pool and uses the reliability criteria of the Pool. That criteria requires that individual systems maintain minimum capacity margins of 15.25 percent or as an alternative, the loss of load probability shall not be greater than one occurrence in ten years. In addition, provides reserves sufficient to cover the loss of the largest generating unit. At this time, an in-depth study of the relationship between reliability and the costs of achieving that reliability is in progress. The economically desirable level of reliability will be determined. Approximately 12% of our sales are made to heavy industrial customers engaged in and Momentary loss of power to a typical plant represents 6 to 7 days loss of production; in addition, approximately $500,000 for overtime, parts and equipment are necessary to return the plant to production. An unplanned power outage for such customers produces a real threat of freeze-up, explosion, fire, loss of property and life, the value of which is not included above.

The generation reliability standards utilized are 1 day in 10 years loss-of-load probability (LOLP) with tie line assistance and 6 days per year LOLP on an isolated basis. The transmission reliability standard includes single contingency criteria which states that all load shall be served with any one facility out of service. A generation reliability value study is currently under way.

[redacted] is a member of the Mid-America Interconnected Network (MAIN) Electric Reliability Council and endorses MAIN's criterion with respect to planning of generation reserve. A statement of that criterion is "Current analysis suggests maintaining a minimum reserve for MAIN members of 15% to 20%." This criterion is approximately equivalent to a one day in 10 years Loss of Load Probability (LOLP) expectation in the MAIN LOLP Studies.

[redacted] conforms to the Northeast Power Coordinating Council (NPCC) Basic Design Criteria and NYPP Standards. These criteria include no more than one (on average) non-interruptible customer disconnection due to generation deficiency in 10 years and also include first contingency thermal, voltage and stability design and operating requirements. NYPP has performed reliability assessments which, in conjunction with various emergency operating procedures, estimate the frequency of voltage reductions, public appeals and load disconnections as a function of installed generation reserve to establish minimum reserve requirements.

Reliability standards used were developed by the Mid-Continent Area Power Pool (MAPP), of which [redacted] is a member. The MAPP generating capacity reserve requirement of 15% is [redacted] supply reliability criteria. Transmission reliability standards require meeting defined (single and multiple) unscheduled contingencies without instability, cascading, or service interruptions. No studies have been performed quantifying the value of reliability to [redacted] customers.

The adequacy criterion adopted by MAIN, regional reliability council, is an LOLP of .1 day per year or better, which is equivalent to 1 day in 10 years. EPRI and others are performing research in the area of customer outage costs and until such time as these costs can be estimated with greater certainty than available today, will rely on MAIN studies and be guided by the results of value of service evaluations.

Generating capacity requirements are based on a loss of load probability of 1 day in 10 years. Transmission requirements are based on analysis of single contingencies, contingencies involving loss of both circuits on a common structure and contingencies involving outage of a transmission facility and a "stuck breaker." Stability tests include three phase faults with primary clearing and single phase faults with back-up clearing. We have not performed studies quantifying the value of reliability to customers.

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10. is a member of the Southwest Power Pool and uses the reliability criteria of the Pool. That criteria requires that individual systems maintain minimum capacity margins of 15.25 percent or as an alternative, the loss of load probability shall not be greater than one occurrence in ten years. In addition, provides reserves sufficient to cover the loss of the largest generating unit. At this time, an in-depth study of the relationship between reliability and the costs of achieving that reliability is in progress. The economically desirable level of reliability will be determined. Approximately 12% of our sales are made to heavy industrial customers engaged in and Momentary loss of power to a typical plant represents 6 to 7 days loss of production; in addition, approximately $500,000 for overtime, parts and equipment are necessary to return the plant to production. An unplanned power outage for such customers produces a real threat of freeze-up, explosion, fire, loss of property and life, the value of which is not included above.

One day in ten year LOLP for resource planning, first contingency for operational scheduling. No studies.

_____ uses the reliability criteria of the Southwest Power Pool which requires an 18% reserve margin or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available shall not be greater than one occurrence in ten years provided that the minimum reserve shall not be less than 15% for steam-based utilities like _____. _____ uses this 15% reserve level based on probability studies it has done.

Stability criteria requires that the system remain stable for any three-phase fault with normal fault clearing or any single-phase to ground fault with delayed fault clearing on one breaker.

_____ current reliability index is 168 ~~hours~~ loss-of-load expectation per year for an isolated system. _____ participated in an EPRI study entitled "Cost and Benefits of Over/Under Capacity in Electric Power System Planning." Methodologies used in this study have been used by _____ to determine its reliability index.

1 day in 10 years. _____ has not estimated the value of reliability to customers.

1 day in 10 years. Studies have not been done to quantify the value of reliability.

Response:

For planning purposes, currently uses a minimum installed reserve margin criterion of 20% (which corresponds to a 16.7% capacity margin) to schedule generation additions and maintain adequate and reliable electric service. The Company has used the percentage of reserve or reserve margin as the standard of system reliability since the early 1970s. Other measures, such as Loss of Load Probability (LOLP), Loss of Energy Probability, Frequency and Duration, etc., are also used as planning tools. The percentage of installed reserve is determined by the installed generation capability along with firm contracted capacity which is greater than the requirement to meet the one-hour summer territorial peak demand. The 20% minimum reserve margin standard has been molded by analysis of system operating history, the influence of regulatory bodies and management judgment. reliability criterion has been supported by the

Because probabilistic reliability indicators (such as LOLP) are complex, differ based on the computer model used to develop them, and vary from utility to utility, does not feel that it is appropriate to provide such values.

has not performed studies quantifying the value of reliability to its customers.

criteria requires reserves equal to the largest unit or 15% of forecasted load responsibility, whichever is greater. periodically runs loss of load probability to see if loss of load probability is within 1 day in 10 years. Stability criteria requires system remain stable for any 3 phase fault with normal fault clearing or any single phase to ground fault with delayed fault clearing on one breaker.

utilizes the Southwest Power Pool Reliability Criteria for capacity planning and reliability purposes. The Southwest Power Pool Reliability Criteria requires a minimum capacity margin of 13% (which equates to a 15% reserve margin, i.e. 15% of forecasted load responsibility) for steam-based utilities. Although not done on a routine basis, loss of load probability (LOLP) studies have been performed to determine that planning capacity margin levels meet the criteria established by the Southwest Power Pool. Such criteria requires that the probability of load exceeding the amount of available capacity shall not be greater than one occurrence in ten years. Sound engineering judgment and substantial electric industry experience has demonstrated that the Southwest Power Pool Reliability Criteria provides with reasonable levels of reliability.

Stability criteria requires system remain stable for any 3 phase fault with normal fault clearing or any single phase to ground fault with delayed fault clearing on one breaker.

Reliability standards that currently uses include the following:

1) uses a 15% reserve margin criterion.

2) Transmission capacity is provided to import firm power at least equal to the planned net import plus the capacity of the largest generating unit less online spinning reserve with any single transmission line out of service.

3) Transmission capacity is provided to export power at least equal to the planned net export plus the planned internal online spinning reserve.

4) For single contingencies transmission voltage limits range from 90 to 105%.

5) Transmission lines and transformers are not loaded above their maximum thermal rating during single contingencies.

6) Severe contingencies such as the outage of a multiple circuit transmission line sections should result in no uncontrolled islanding or loss of large amounts of load.

The 1 day in 10 year criterion is considered and attained by subscribing to a 15% reserve margin which has provided loss of load probability results that are somewhat better than 1 day in 10 years. has not performed rigorous studies in an attempt to quantify the dollar value of reliability to our customers. We know, in general, that on a mild spring or fall day many customers are less concerned about the reliability of electric power. However, on a cold winter night or hot summer day, customers are normally very concerned about having a reliable power supply. We also know that the cost of an outage is customer specific. Stability criteria requires system remain stable for any 3 phase fault with normal fault clearing or any single phase to ground fault with delayed fault clearing on one breaker.

Question 10

The System does not adhere to a specific rigid index, such as a given loss of load probability, in planning for the addition of generating capacity. However, a 20% reserve margin is considered a "trigger point" at which more detailed analyses are initiated.

In accordance with the provisions of the East Central Area Reliability Coordination Agreement (ECAR), the bulk transmission network is planned, built and operated to meet the reliability criteria described in ECAR Document No. 1. Using these criteria, simulated testing is conducted to assure that no uncontrolled, area-wide power interruptions will occur under credible contingencies, such as the sudden loss of a major generating plant, a station, or a load center. While the testing criteria themselves are deterministic in nature, the specific tests that are selected for this purpose reflect the probability of a particular disturbance based on actual operating experience.

The reliability criteria, as applied to area supply facilities, utilize probability techniques to measure the level of service reliability provided by the network. This approach considers: 1) the probability of a critical outage occurring at the time when area loads are at critical levels, and 2) the likelihood of heavily loaded equipment failing at the time of the system contingency. The various parameters used in this evaluation process are continually reviewed and updated. Studies to quantify the value of reliability from the customer's perspective have not been carried out.

QUESTION 11

UNDER PRESENT CONDITIONS, DO YOU CONSIDER CONSTRUCTION OF NEW CAPACITY TO BE A HIGH FINANCIAL RISK? IF SO, WHY?

Yes. There is a substantial amount of uncertainty about the standards of prudency and "used and useful" utility plant that will be applied by the regulatory commission in determining allowable cost recovery of any new capacity.

expansion plans do not call for new capacity until the late 1990's and have not yet been affected by the risks discussed in Question 11. Thus, a reduction of such risks through prior and periodic regulatory approvals would not change these plans.

Yes, present state certificate of need legislation requires a rolling two year review of the projects. No assurance that a utility will recover sunk costs if a review finds the project not needed.

Somewhat, particularly for large increments of capacity or projects with long construction lead time. However, recent experience for has been positive. completed a large (800 MW) project on time and below budget in late 1987.

It can be but the degree of risk is a functicn of numerous factors such as size, type, and location of the new capacity as well as the cost of the project and the financial condition of the company considering construction.

Expenditures in new capacity can carry the highest financial risk of any utility investment. Because of the length of time between project commencement and project completion, forecasts at the time of project conception versus those conditions which exist at the time of project completion may not bear close resemblance to one another. Additionally, although there remains a very constant obligation-to-serve concept, there is an increasing erosion in the utility's opportunity-to-serve. These allow for the possibility of prudency reviews with "hindsight" information not available to the utility management at the time the decision to commence with the project had to be made.

Very high risk because of the lack of CWIP and tendency for after the fact prudency review.

Yes. Long lead times for construction, with potential changes in costs and regulations governing construction; uncertainties of load forecasts; potential cost disallowances by regulatory authorities.

Yes, because load growth and costs of construction are highly uncertain.

Yes, because of the magnitude of the required investment, uncertainty of the exact timing of future need, and regulatory attitudes towards disallowance of investment recovery based on after-the-fact "prudence" reviews.

Yes, regulatory treatment.

Yes. Uncertainty in politically sensitive rules and legislation dealing with environmental and regulatory constraints combined with the sometimes changing nature of the regulator's themslves does create a high financial risk. I would be remiss if I did not mention a trend toward an improvement in the compact between the utilities and their regulators.

Response:

Under present conditions, the financial risks of committing large sums of capital for construction of new capacity are high. The risks have increased due to the breakdown of the traditional regulatory compact. Rate phase-ins and disallowances through after-the-fact prudence reviews have been the regulatory response to the high cost of construction of new capacity. The long leadtimes for construction of new baseload capacity and the resulting long exposure to unforeseen future events increase the risk of regulatory disallowances. High construction costs and long leadtimes before rate relief, and potential disallowances through hindsight reviews results in high financial risk for utilities.

11. Under present conditions, the construction of long lead time base load nuclear and coal-fired generation has a high financial risk. If any of the parameters used to justify such generation change adversely during construction, the utility may be burdened by disallowances of capital cost in rate base by the utility commissions. Factors which could adversely affect rate base treatment of new generation include, but are not limited to:
    a) lower load growth than projected originally
    b) higher capital costs than original estimates
    c) regulatory action resulting in delays in construction
    d) fuel costs resulting in lower energy savings than projected.

The financial risk associated with large capacity additions is high because of unlikely cost recovery during construction and exposure to prudence disallowance when construction is complete.

In December 1986, completed construction on a baseload coal unit jointly at a cost below $800 per kW. In 1987, the principal owner of the unit, received full rate recognition from the ublic Utility Commission for share of the costs including all costs deferred between the unit's completion and the date new rates went into effect reflecting those costs. This would indicate that, for the future, where utilities construct and own generating units at reasonable costs, regulators will permit recovery of those costs without subjecting the utilities under their jurisdiction to undue financial risk.

Yes. Regulatory uncertainty causing long construction periods and constantly changing rural economic conditions make capacity expansions a high financial risk.

Yes. Major capacity expenditures are considered to be a high financial risk because of risk of recovery through regulation.

No

11. Yes, we currently consider construction of new capacity to be a relatively high financial risk. The reasons we currently believe new construction is an unnecessary risk include the following:

1. Due to the long construction periods of most new plants, utilities find themselves in the position of having spent significant capital to complete new generating resources, in order to meet anticipated load growth, only to find loads do not grow as anticipated. This leaves the utility with high costs to repay the capital expenses, but without the revenue from energy sales to meet those expenses.

2. Many utilities in our region are currently in a position of having significantly more generating capacity than they need to meet their loads. In many cases these utilities are attempting to sell this excess capacity to other utilities. Purchasing power from existing plants is not only less risky from a financial standpoint, it is, in many cases, much less expensive than constructing new plants.

3. The significant capital associated with new plants would, at best, significantly strain our ability to maintain the financial goals of the company.

11.

[redacted] does not consider construction of necessary capacity such a financial risk as to avoid construction. [redacted] designs and builds its own plants on a fast-track, cost-controlled schedule, using sizes and types of plants technically and economically consistent with system capacity requirements and fuel supplies, thereby minimizing risk of cost over-runs.

Long lead times brought on by regulation and constantly changing regulations under any scenario make major capacity additions risky.

QUESTION 12

WOULD A PROCESS OF PRIOR AND PERIODIC REGULATORY APPROVAL ("ROLLING PRUDENCE") ADEQUATELY ADDRESS ANY CONCERNS OVER INVESTING IN NEW CAPACITY? HOW WOULD ROLLING PRUDENCE ALTER YOUR UTILITY'S CAPACITY EXPANSION PLANS AS INDICATED IN QUESTION FIVE (E.G., DIFFERENT FUELS, BASELOAD VS. PEAKING, UNIT SIZE)?

In large measure. Would make option of central station, base load capacity a more viable future option, but would not be applicable in planning time-frame of 1997 as now anticipated. The concept of rolling prudence would reduce financial risk if the periodic approvals were binding on future commissions.

needs, and has plans to construct, peaking capacity. Rolling prudence would not likely change immediate plans; however, a rolling prudence scheme that truly worked might enable installation of capacity, in the future, that due to the risk of not being able to recover the investment, might not be considered, even though that type of capacity would most efficiently serve the needs of our customers.

12. is not in a regulatory environment where disallowance of construction expenditures has been a problem. Therefore, since our concerns about investing in new capital projects are not based upon the risk that expenditures may be disallowed, a process of prior and periodic regulatory approval would not address our concerns about the risks of new construction.

No. It is unlikely that the opportunity for after-the-fact review would actually be waived. Any system thorough enough to constitute a binding commitment from the regulatory authority would likely delay construction -- particularly for a multi-state utility.

Rolling prudence would not alleviate the risk associated with large capacity additions because it does not allow interim cost recovery. Construction work in progress, in the rate base, on the other hand, would allow cost recovery as projects progress in order to provide an incentive for continued investment. Without construction work in progress, expansion may be limited to economically suboptimal facilities.

See item 11, "Rolling Prudence" review must assure recovery of all costs that the utility has occurred up to the current review period. "Rolling Prudence" would probably result in selection of short lead time projects.

A process of prior and periodic regulatory approvals, if the Commission were obligated to allow cost recovery based on such approvals, would substantially reduce the financial risks associated with adding capacity.

Such periodic review and approval would not be adequate because future regulators are not bound by decisions made by today's regulators.

Not applicable. rates are not regulated by the State Public Service Commission but we must obtain applicable State/Federal approvals to construct new capacity similar to investor-owned utilities and we must provide generation at lower cost to be competitive and remain in business.

is opposed to the concept of periodic regulatory approval. It is viewed as an unnecessary intrusion into the management decisions involved in the choosing, designing, and building of new capacity. the utilities are required to obtain prior approval before beginning construction of new facilities. Additionally, there is a burden on the utility to demonstrate that its own plans underwent self scrutiny on a periodic basis, and that at all times during the construction of the facility, decisions were made to cause the lowest revenue requirements impact on the utility's customers. Periodic regulatory approval, given the requirements already in effect will not diminish the financial risk associated with new capacity expenditures, and may well result in severe delays in completion of capacity additions.

12. Prior and periodic regulatory approval would not eliminate concerns over investing in new capacity unless the utility was provided full recovery of and return on any investment subsequently disallowed in a periodic review. Current state law permits only a recovery of, but not a return on, prudently incurred costs of any partially completed facility when cancellation is found by the State Regulatory Commission to be in the public interest. Consequently, periodic regulatory approval would significantly increase the financial risk of new construction. Our response to question 5 showed only one new unit, a large MW nuclear unit, which has been subjected to several prudence reviews and a cost cap by the State Regulatory Commission. Such reviews have neither altered our expansion plans nor have they improved financing of this new capacity. The concept of periodic regulatory review also has the inherent risk that during the time needed to construct new capacity, the membership of a regulatory commission could change such that a later commission may disavow previous approval of construction.

Yes; "Rolling Prudence" would lessen the most important uncertainty, that of future investment recovery. It would not affect near-term plans indicated in response 5, but would affect long-term plans.

believes that it is preferable to mitigate financial risk by developing flexible resource addition plans, reducing construction lead time, and adding moderate and appropriately sized (150-400 MW) increments of capacity Rolling prudence would be unwelcome additional regulation and would not be expected to alter expansion plans. Current regulatory frameworks (Certification of need prior to construction) function satisfactorily.

does not think State Regulatory Commissions will ever adopt rolling prudence reviews because rolling prudence reviews require State Commissions to make decisions which are the responsibility of utility management. response to question 30 (a question prepared by) indicates that utility managements are now in an excellent position to select the most economical generation mix, with or without rolling prudence reviews. Assuming does select the most economical generating mix, recovery of the associated costs should not be a problem under traditional regulatory practices which do not include rolling prudence reviews.

12.
Prior regulatory approval required in jurisdictions adequately addresses these concerns. Rolling prudency reviews would not have altered capacity expansion plans in the past and are more likely to create political mischief than cost savings in the future. If such a review process is implemented, it is imperative that the evaluation of prudency is made at the time of utility commitment.

"Rolling Prudence" would not alter our expansion plan.

Each of the three states in which we operate require a Certificate of Convenience and Necessity prior to the construction of new projects. We believe that process is sufficient to protect the appropriate interest. The proposal of "rolling prudence" would result in delays, additional cost and some shifting of the utilities burden to its regulators.

No, since such approval could not reduce uncertainty but only shift responsibility.

Not totally.

Response:

Rolling prudence is an idea contemplated by many in the electric utility industry as part of a larger package of regulatory reform that would be aimed at strengthening the so called regulatory compact or the regulatory-utility bargain. This part of the package would be intended to address the uncertainties that the typical investor owned utility faces in the process of selecting the supply options which best meet the load it is obligated to serve.

While economic efficiencies, fuel economies, and geographic locational advantages may indicate that capital investments be made at central station sites, a hesitancy to make those kinds of capital investments exists. The uncertainty associated with disallowances and questionable recovery methods adopted in some jurisdictions, may in some cases influence planning to be more economically safe than sound.

While we believe that the rolling prudence concept can help resolve some of the industry's concerns over investing in new capacity, there are pitfalls. Some rolling prudence proposals would effectively hamstring the utilities efforts to plan, design, and construct new facilities and in the long run would result in less reliable service and higher costs to consumers.

There are of course a large number of possible ways to implement such a rolling prudence review. Realistically, each jurisdictional utility and regulatory authority must settle upon that prudence procedure which best resolves the difficulties germane to that area. The difficulty is of course the implementation of a system which not only protects the utility and its customers, but also allows room for the utility to effectively function as an efficient free enterprise endeavor.

(Continued)

The impact of rolling prudence on our capacity expansion plans would depend upon the specifics of the process adopted by our regulators. However, we speculate that a rolling prudence process would have only minimal impact on our current capacity expansion plans.

QUESTION 15

HOW DOES THE SIZE, COST, FUEL USE, AVAILABILITY, AND RELIABILITY OF NUG POWER COMPARE WITH THAT OF THE PLANTS THAT YOUR UTILITY HAS NOT OR WOULD CONSIDER BUILDING?

No data to compare, but would question the reliability and availability of such units.

Size - generally much smaller

Fuel Use - greater use of natural gas as compared to coal

Cost - Unknown; no data available

Availability and Reliability - Unknown; no data available

We generally know only the size of the NUG generating unit and are not privy to the other items mentioned in this question. We added two COAL fueled units in 1985 and 1986 respectively in two different states at a cost of $764/KW and $864/KW.

The only currently proposed NUG is too large for our existing system, would burn coal and does not appear feasible to us. There is, however, the potential for small hydro in the area.

Response:

has not gone through a solicitation process for additional capacity. We are not in a capacity short situation and do not expect to need additional capacity until the mid-1990s.

However, we currently have approximately 400 MW of QF capacity on our system and based on our experience with these facilities, we offer the following comments.

Size: The size of QFs are generally smaller than our existing plants. The plants range in size from 80 KW up to 97,000 KW.

Fuel Use: Fuel use is primarily coal which is comparable to our major fuel use.

Availability & Reliability: has had QF capacity on its system for a relatively few number of years. Our limited experience has been that the availability and reliability of QFs generally compares well with that experienced at our plants. However, since we don't control the dispatch of power from these facilities and because they are not regulated, the long-term stability and reliability of this capacity is uncertain.

Generally, NUG power sources with capacity greater than about 20 MW have demonstrated greater availability than central fossil plants. Conversely, the smaller NUG power sources (less than 20 MW) have not demonstrated availability greater than our central station plants.

With only 1.2 megawatts of NUG power on its system, the does not have sufficient data to make this comparison. Believe unlikely NUGs would have comparable availability and reliability of Company's present plants.

Extensive use of liquid and gas fuels would also be a concern from standpoint of long-term cost stability and predictability, and of long-term availability.

Resource recovery and other small power production are smaller in size, cogeneration facilities vary in size but larger projects (100-200 MW) range are comparable. Over reliance of natural gas for cogeneration. Availability and reliability cannot be determined due to lack of operating experience.

The current excess of QF capacity available in ~~the state~~ has allowed to negotiate favorable price and non-price terms and conditions which assure a high level of reliability. A buyer's market has permitted selection of quality QFs, so reliability has been good. uses some combustion turbines similar to those used by QFs as a component of generation resources. However, QF dependence on natural gas limits the percent base load which can be prudently served by QF sources. At best, future service quality is only as good as the willingness and ability of the QF seller to honor its contractual commitments.

At the present time, has virtually no NUG capacity on its system. Of the existing self-generators, the size of the units is small in comparison to units would consider. We have little information on the other factors listed.

No experience with NUG's on system.

15. The size of Non-Utility Generators tends to be much smaller than either existing or proposed generation units. The cost per kW of Non-Utility generation capacity tends to be lower than the cost per kW of the next (coal-fired) generating plant which we would consider building. Non-Utility generators in our service area use natural gas as fuel almost exclusively, whereas about 80% of the GWH produced by are from coal. Availability and reliability of Non-Utility generators are at least equal to generating stations.

15. The size, design and fuel characteristics of the NUGs on the system are not comparable to units. Based on very limited data, it would appear that the availability and reliability of existing NUG power has been comparable to our own units.

Not available.

Most units are smaller than utility generation and therefore cost more per kW. Most use natural gas. Availability and reliability varies considerably between QFs. Some are very good and some are very bad.

The megawatt capacity of NUG generating units in territory is substantially smaller than current generating units or the next series of generating units presently planned to be constructed by 2001. Even considering in the aggregate the total stated capacity value of the existing NUG facilities, there is not sufficient dependable generating capability during peak demand periods to cause to delay construction of generating units.

The two largest NUGs in the system burn natural gas and city refuse. Of the NUG facilities being considered for future installation, the primary fuel will be natural gas. One NUG facility plans to utilize city refuse as a fuel source. Some hydroelectric units are also being considered. Such fuel sources compare to planned future use of coal and lignite for base-load units and natural gas for peaking units.

does not have specific information of the present or future installed costs of NUG facilities. Consequently, no reliable cost comparison to existing or planned generating units are available.

The issues associated with availability and reliability of NUGs are complex and, in most cases, cannot be readily quantified. No reliable comparison with generating units are available.

It should be noted first that has had limited experience with NUG, and second that size, cost, fuel use, availability and reliability are highly variable characteristics. These characteristics are dependent upon processes associated with NUG (chemical plants, petroleum process plants, "power for profit" installations, etc.), location, type of equipment (new, used, or experimental), maintenance practices, fuel purchase practices (e.g., firm, spot or surplus), operator training and other variables associated with the total economies of the NUG installation. experience suggests:

Size: .... that NUG size is not predictable but can range from a few KW to 50-100 MW. NUG unit size would generally be significantly smaller than now has or would consider building, with the possible exception of peaking combustion turbines.

Cost: .... that total capital and operating cost of NUG is driven by the same variable as our own cost and, while variables, would not differ significantly over time (with the exception of true cogeneration where process economies can be achieved).

Fuel Use: .... that most NUG would be natural gas fueled. generation is now 75% natural gas fueled (with fuel oil backup) and 25% coal fueled. Future base load generation is anticipated to be coal fired, while peaking and intermediate duty generation may be natural gas fired.

Availability and Reliability: .... that availability and reliability for NUG units would tend to be lower than that of units.

Answer. Current NUG projects are primarily small hydro and municipal solid waste (MSW) plants. has developed similar facilities by retrofitting older existing plants to use MSW, and has done, and will continue to make modest capacity upgrades at existing hydro plants. However, these types of facilities only satisfy a small part of capacity requirements. The NUGs on our system tend to be smaller and have higher capital costs than facilities would likely consider to provide the bulk of energy needs. Coal or lignite will be the dominant fuel resource considered by for most newly constructed plants in the foreseeable future.

NUGs size is generally smaller, their installed cost is generally higher per KW, and their fuel is primarily waste or biomass with supplemental gas, coal, and oil. Presently, information available for historical analysis shows only the net input to our system. Therefore, the availability or reliability of these units is unknown.

Size would generally be smaller. Fuel use, availability and reliability would compare to natural gas/oil fired gas turbines or steam units.

15.
The criteria for design, installation and operation of NUG units vary widely with the particular application. The size is generally smaller. Cost comparisons must be evaluated on an individual basis. Availability may be comparable but NUG unit reliability is usually less due to operations and maintenance being performed by less experienced crews, as compared to a utility-owned facility.

The identified NUG capacity in Item 13 is primarily from cogeneration and represents loads formerly served by . . In general, these NUG's were installed with coal-fired fluidized bed boiler designs for process steam requirements. These plants are newly constructed and no data is available on cost, availability or reliability.

QUESTION 16

WHAT PLANNING AND OPERATING DIFFICULTIES, IF ANY, HAVE YOU ENCOUNTERED TO DATE WITH INTEGRATING NUGS INTO YOUR SYSTEM?

The amount of NUG capacity in our service territory is small. Its effect on planning and operating has been insignificant. Our problems have primarily involved relay protection at the interface with NUGs connected to the distribution system.

3) IPP's and PURPA QFs combined.

4) Estimate available for 1992.

5) In service territory but not connected to system.

From a planning perspective, the NUGs that are integrated into generation planning are more often delayed or cancelled than are company facilities.

From an operating perspective, the NUGs are not bound by desired generation schedules, do not contribute to automatic generation control, and do not communicate with system operations as well as system units/plants do. Additionally, more effort, care, and coordination is needed when scheduling and conducting transmission maintenance when NUGs are effected or involved.

Relay coordination and maintenance problems of the NUGs equipment have lowered the quality of service to our other customers.

Not applicable, no NUG's on our system.

No experience in operating with NUGs.

Without being able to dispatch the NUGs it is more difficult to operate under minimum load conditions (units hitting their lower limits). Also, scheduling maintenance for . generation is much more difficult since the NUGs can go from being a supplier to a purchaser at any time.

NUGs are beginning to proliferate in our system. Of concern is the concentration of significant NUG capacity in areas with limited transmission capacity. The aggregate effect will be to create circuit overloads and circuit breaker overstresses, requiring comprehensive, area wide reinforcements. Voltage regulation and reactive control has been a problem with small NUG using induction generators.

Very little difficulty has been encountered with existing self-generators once any interconnection issues are addressed.

As a result of the previously mentioned negotiations with QFs and careful monitoring to assure rigid contract compliance, major problems in integrating NUGs into the . lectric System have not been encountered to date.

We currently have no NUGs in our area.

16. No planning difficulties have been encountered to date with the integration of NUGs into our system.

The main operational difficulty has been the issue of instantaneous reclosure of utility system circuit breakers. Breakers are generally set to reclose instantaneously after tripping. This rapid reclosure can cause major problems with a NUG reconnecting out of phase. A survey of other utilities was conducted to determine their responses to this problem. Currently, the breakers on circuits affected by NUGs are set for a delayed reclosure time in response to this problem.

16. No significant difficulties have been encountered. Of the 13 NUGs 1 MW or larger presently in service, 10 were in service prior to PURPA and supply a portion of the owner's energy requirements rather than selling to Two NUGs over 50 MW recently placed in service have required special metering treatment to provide our system operator with hourly output data.

None. Very few small QF projects are connected to the at this time. The industrial generators installed supply the electrical/steam requirements of the industrial's process. In many instances, supplements the electrical supply. The industrial generator does not provide electrical power to

Uncertainty about the length of time capacity from NUGs will be available to meet our long term capacity requirements. Difficulty getting an accurate account of daily energy, since current projects are small (less than 5 MW). Other difficulties may result with the expected addition of larger projects (40MW or greater) in the future.

Response:

PURPA QF facilities currently represent a relatively small part of total power resources. The problems have been mitigated by this fact as well as the Company's overall coordination efforts. It is noteworthy, however, that the uncertainty associated with future cogeneration including the possible location of cogenerators, the reliability of future cogenerators, compatibility of the operating systems, and coordination with these facilities has expanded the Company's overall planning and operating efforts.

From an operating stand point, lack of dispatch control over cogenerators has been a problem (especially during minimum load conditions).

has experienced the situation where a NUG facility has ceased generation of electric energy because it became an unprofitable business venture. Instances like this can cause difficulties in the areas of generation, transmission and fuel planning. Planning in these three areas requires significant lead time for a utility and cannot plan in these areas with any certainty regarding the existence or availability of NUGs. As the number of NUGs on the system increase, operation of the system becomes more difficult and complex. More real time communications, telemetering and information exchange will be required. Complexities of operating the system are multiplied during normal and emergency conditions.

16.
In the past, generating plants were planned and operated assuming the utility had complete control over each unit. Integrating NUGs into the electrical system results in planning and operating difficulties because of the utility's limited influence over the units' dispatchability, committment, maintenance scheduling and operating life. The utility can compensate for lack of control by raising capacity reserve margins at the customers' expense.

None.

As mentioned above, has, to date, limited direct experience with NUG. We have experienced the complexities of working with proposed projects. In these instances, the prospective owner/ operator of the NUG had little appreciation for the engineering and operating difficulties of generation attached to a large network. In addition, we had experience with one installation on the system of a full requirements wholesale customer. In this case, the full requirements customer and the NUG refused to install some recommended protective equipment. The result, on two occasions, was major damage to the approximate 450 KW generator.

Some costs have been incurred to upgrade utility circuit breakers due to increased short circuit duties caused by adding NUG generation.

Minimal. The limited number of NUGs on our system primarily supply on-site requirements only and their interconnection has had negligible impact on planning and operation. However, a non-utility generator desiring to serve customers outside our service territory, one outside desiring to serve our customers or wheeling with our service territory that was not planned, coordinated and built for could have adverse effect on a transmission system not designed for such a transfer.

The only proposed NUG is too large to permit our base load plant to remain on line. They expect an excessively high avoided cost with no operational control by the utility.

The company has only one NUG currently on its sytem, and this NUG does not sell capacity or energy to the company.

QUESTION 19

UNDER WHAT CIRCUMSTANCES (E.G., % INSTALLED CAPACITY, SIZE OF INDIVIDUAL NUGS, LOCATIONS) WOULD A LACK OF THE CHARACTERISTICS LISTED IN QUESTIONS 17 AND 18 SIGNIFICANTLY IMPACT SYSTEM RELIABILITY AND COST, REQUIRING MAJOR CHANGES TO YOUR PLANNING AND OPERATIONS?

Response:

It would be extremely difficult for a purchasing utility (even with direct dispatch control of all NUG units) to economically dispatch all available units "in a load following mode" based on system lambdas, as is currently the practice. The dispatching order would obviously be influenced by take-or-pay contract obligations, resulting in a loss of the savings produced by economic dispatch. This problem would become worse with the addition of each new NUG unit covered by take-or-pay obligations and would be further exacerbated by the aging of those units. As units age, their increased operating and maintenance costs move them down in a dispatch order dictated by principles of economic dispatch, which may not be possible, however, if they must be operated to comply with a take-or-pay obligation despite their increased O&M costs.

Currently, electric utilities plan and operate their systems, from generation to transmission to distribution, on a highly coordinated and integrated basis. Any changes occurring at any level of that system require that related changes be made at other levels (e.g., shifts in distribution load centers require changes to the transmission system, and possible changes in the planned location of generating units). Similarly, savings at one level can often be achieved by design and operating decisions made at another level (e.g., centralized location of large, baseload plants minimizes investment in the transmission network).

For these reasons, any shift to smaller generating units caused by changes in FERC rules could require that the transmission and distribution systems of particular utilities be redesigned, and investment costs incurred, in order to effectively incorporate those units into the system. Admittedly, it is extremely difficult to generalize about the specific kinds of system changes that would have to be made, and their costs, for the simple reason that the changes would depend upon the specific system configuration of the particular affected utility. However, it is impossible to assess accurately the economics of NUG supplied power without considering the cost of any changes in system configuration required to incorporate that power into the system.

From engineering and operating standpoints, it is impossible to separate generation facilities within an electric utility control area from the transmission and distribution facilities which deliver the power to locations where and when it is needed, because, in a very real sense, the entire control area operates as one large machine. (For example, the transmission of electricity can only be accomplished by means of the coordinated operation of generating units.) For that same reason, it is impossible for that control area to be operated efficiently, reliably and safely if control of some of the generation committed to the system's needs is separated from control of the remainder of such generation. The coordinated planning and operation of a utility control area is typically achieved largely within the organization of a single, vertically integrated electric utility, which is responsible for and directly controls the planning, construction and operation of all aspects of its system, from generation to transmission to distribution. The inevitable effect of increasing NUG capacity would be to create uncertainties for the utility at each stage of the process because of the loss of that direct control.

NUGs now supply approximately 100 MW of non-firm power. This amount has required to make adjustments to its minimum load operations plus increased the complexity of maintenance scheduling since this 100 MW of generation could potentially turn into a significant amount of load if the NUGs are down for maintenance.

19.
As NUGs become a significant percentage of system capability, normal operating criteria may be compromised. If NUG units are large compared to other units on the system, operating reserve requirements would increase, resulting in additional costs. NUGs located in transmission constrained areas would adversely affect reliability.

First, the lack of the characteristics listed in questions 17 and 18 can always have significant impact on system reliability, cost and, importantly, personnel and public safety in some circumstances. The key variable is control. The characteristics listed in questions 17 and 18 determine whether or not there is coordinated control of the power system, whether the integrity of the system takes precedence, whether reliability of service to the ultimate customer takes precedence, and whether enough information and control resides at a central location in order to make intelligent, timely decisions.

The possible impacts become even larger when

a) a NUG unit or plant represents a significant portion of system or area generation.

b) a NUG unit or plant is located at a relatively weak spot in the transmission or distribution system.

c) any NUG does not carry spinning reserve to help cover the loss of system generating capacity.

d) any NUG supplying long term firm capacity ceases to exist or suffers a deterioration in reliability and availability.

If any NUG capacity was used, all parts of 18 could significantly affect cost. If significant NUG capacity was employed, 17 and 18 (b, d, & e) could significantly affect reliability.

has not had the opportunity or the necessity of studying these circumstances.

As more NUG capacity is added in base load generation, it places increased costs for spinning reserve, area regulation, etc., on utility plants thus increasing cost of operations.

We identify over 25 non-price factors in selecting NUGs from which to purchase power, all of which have variable impacts on System reliability depending upon the planning environment. Decreased ability to negotiate appropriate non-price factors in contracts with NUGs would negatively impact the System's reliability and cost and could require planning and operations adjustments.

Answer. Lack of voltage regulation from NUGs, or the absence of control of NUGs for maintenance scheduling, security dispatch and system emergencies could have major impact on a particular area. However, it is our judgment that total capacity from NUGs would have to be at least 3% of installed capacity, or individual NUGs greater than 50MW, in order to significantly impact system reliability and cost.

No experience with NUCs.

19. Lack of the lock-out capability noted above would not be acceptable from a safety standpoint; extreme difficulties would be encountered if this capability were not available.

Large NUGs present operational difficulties in maintaining system reliability. Units over approximately 2% of the total installed utility generation, or approximately 70MW at this time, would present such difficulties. On a case-by-case basis, certain locations on our system would be more problematical than others.

A small percent of installed capacity spread over dozens of small units without proper utility control could have a significant impact on cost related to unit commitment, economic dispatch, and reliability.

Numerous units, units over about 50 MW in size, or sum total capacity over approximately 3% of total load, if not controlled by our utility, can cause significant problems in all seven areas listed in questions 17 and 18. If does not have dispatch control or coordinated scheduling with a NUG, actions taken by the NUG may be contrary to system. This would force us to counter the NUG action, in addition to taking the correct action.

(a) Heavy concentrations of NUG capacity at remote locations. (b) Penetration of NUG capacity, in areas with already high short circuit levels. (c) Systems that already have too much base load capacity.

At the point where a NUG, or NUGs as a group are significant enough in size or location to measurably affect ones system, then that NUG(s) would have to be incorporated into system planning efforts and the NUG impact on all operations, including dispatchability, would have to be carefully reviewed.

Potential impacts are site specific.

The proposed 50 MW nondispatchable NUG would prevent operation of existing base load plant.

o depends to significant degree on service voltage connection and location

o could impact local area planning and operations

o impact sizes: distribution 1 MW; subtransmission 5 MW; transmission 50 MW; generation planning and dispatch 200-400 MW total

Any of the circumstances cited as examples above could have a significant impact on system reliability and cost and would deal with these on a case by case basis when, and if, such NUG's are proposed within our system.

Probably individual units larger than 50 MW, and/or total NUG capacity exceeding about 1% of system load.

It is difficult to identify at what total NUGs installed capacity, etc. the lack of characteristics listed in questions 17 and 18 impact the system. Certainly if all of the characteristics listed in questions 17 and 18 of NUGs were under the control of the utility as its units are the system would be operated more securely and more economically. Generally, the larger the NUG capacity is in relation to utility system size and/or load, the greater the problems.

19. Our responses to this and other questions referring to the characteristics listed in questions 17 and 18 consider QFs differently than IPPs. All QFs on the system must adhere to specifications covering parallel operation. These specifications currently provide for control only during system emergencies and restorations (18e). If the proportion of QF power on the system increases significantly, utility control of dispatch, commitment and maintenance would be necessary.

IPPs would most likely be designed specifically to meet system capacity requirements. Consequently, all of the characteristics listed in questions 17 and 18 should be applicable to IPPs 50 MW or larger. To do otherwise would impose greater responsibility and associated cost for system regulation on existing units, and would increase operating costs resulting from reduced capability for economic unit commitment and dispatch.

QUESTION 20

CAN YOU ACCURATELY CALCULATE THE RELIABILITY AND ECONOMIC IMPACTS OF HAVING LESS CENTRAL COORDINATION OF THE CHARACTERISTICS LISTED IN QUESTIONS 17 AND 18? WHAT MODELS AND ENGINEERING EXPERTISE ARE REQUIRED?

In a general sense, no. In a particular case, probably yes. In other words, the economics, engineering and operating facts vary so widely that a generic calculation would be of limited use. However, given a proposed facility of a given size and design at a given location, studies can be performed to evaluate reliability and economic impacts. Computer models would generally be required to study unit commitment and economic dispatch, transmission flows and voltages, loss of load probability, transient stability, short circuit, spinning reserve allocation, effects on neighboring systems, and emergency system restoration. In addition, studies and evaluations must be performed regarding field safety and the response of transmission distribution system personnel during maintenance or unplanned outage.

A full range of expertise in all areas of power system planning, engineering and operation would be required.

No, like many things in the utility business it is hard to quantify a reduction to reliability or economics until after the fact.

When central coordination and control is lost, reliability and economics will almost certainly go down. Production costing model and generation reliability models may be used to determine reliability impacts. Economic impacts will be harder to identify and will vary considerably by size and quantity of the NUGs. Normal planning and operation achieve a high percent of maximum reliability and economics of operation because the system can be controlled in both real time and long range time, and the control parameters are known. Uncoordinated and counter-productive actions and operations by the NUGs will reduce reliability and economics of a system.

Response:

The economic and reliability impacts of having less central coordination of the characteristic listed in Question 17 and 18 is one of degrees, depending on the magnitude of NUG capacity introduced to the system. Currently, purchases about 332 MW of NUG capacity of which we have only partial control of the referenced characteristics. This capacity represents about 3.5% of our installed capacity. This small percentage does not pose a significant threat to reliability. However, there are occasions, due to contract provisions where departures from economic dispatch occur and adverse cost impacts are realized. Although we have not attempted to do so, could reasonably estimate the reliability and economic impacts of not having control over the dispatch of the existing NUG capacity. Accuracy would depend to a large extent on the outage data from the NUG operators and Company estimates of any increased downtime of baseload plants due to take or pay contract provisions. A detailed production cost model would be used to estimate these impacts. It would be preferable to use a reliability model to estimate the reliability impacts but we don't currently employ such a model. As each additional NUG unit is added to the system, the degree of difficulty in estimating these impacts would increase exponentially. This is because all of the possible configurations of unit loadings (fully available, not available, and points between) must be simulated by the computer model for each hour of each year. Furthermore, as the percentage of NUG installed capacity increases, additional cost impacts should be considered, such as the need for additional reserve capacity, additional transmission facilities, and greater spinning reserve requirements to maintain system integrity. Presently, we don't have the resources, data, or experience needed to accurately calculate the reliability and economic impacts of such a scenario.

20.
Yes, if sufficient, accurate and detailed data can be obtained. Electrical performance can be calculated by using power flow and transient stability computer models. Economic reliability, and maintenance performance can be calculated using production cost simulation and maintenance planning computer models. Considerable engineering expertise in circuit theory, power system operations and engineering economics is required to accurately apply these models and interpret their results.

Calculations can be made given good assumptions (i.e., sizes and locations). Tools to use include load flow, stability, short circuit, unit commitment, and production costing.

- has not calculated the reliability and economic impacts of less central coordination.

All our NUGs are self-generating with load and contract requirements that make it imprudent to swing on or with our system. Since there is a problem with knowing how to add NUGs to the existing utility base, accuracy in calculation is difficult. The addition of NUGs to our system to serve load should be expected to bear the same control that our own units face or face significant constraints. Sales off system by NUGs would be even more budensome.

No

Engineering expertise and models exist to calculate impacts on reliability and economics. The results would be dependent on the assumptions made. Using a constant reliability assumption, costs will necessarily rise since loss of central control would diminish the assurance of reliability. Additional capacity would have to be added to offset this uncertainty. Similarly, with a fixed cost assumption, reliability assurance would suffer.

20. The impacts of having less central coordination of the characteristics in questions 17 and 18 cannot be calculated since we have basically no control of NUGs on the system except for voltage and frequency regulation, and for emergencies.

A high level of engineering expertise would be required to accurately calculate the value to of having the control characteristics listed in 18 a, b, c, and d. Computer studies for this purpose would include power flow modelling, capacity expansion modelling, detailed load modelling, and the use of a production costing model.

20. Currently available computer programs used for studies of transmission system load flows, transient stability and production cost should be able to calculate such impacts for an IPP 50 MW or larger with reasonable accuracy. Such studies require expertise in system engineering.

Given the size, type, fuel cost, and operating constraints of the proposed NUGs, production costing analysis can identify the impact on system economics. Reliability impact and administrtive costs are more difficult to quantify.

No.

Not accurately. Any such studies would be valid only for the specific conditions modeled, i.e., no generic solution is possible. The models and engineering expertise are the same as those supplied in response to Question #27.

Economic impacts can be calculated using simulation models but additional routines may be needed. Reliability impacts need more work, may or may not be a problem depending on amount of NUG capacity, their actual performance, etc.

No. With less central coordination of the characteristics listed, the availability of NUG capacity will be at the discretion of the owner. There are probably no models which could simulate the actions of the NUG owners.

No, accurate calculations are not possible, but production cost effects of 18a-d could be estimated using production cost models if estimates of NUG operating schedules and characteristics can be made. Production cost impacts for 17a might be approximated by modeling an increased spinning reserve requirement.

We have not analyzed these effects because the amount of NUG capacity on system is too small to have significant impacts on costs or reliability. We are unsure how well existing models will handle these effects.

"Standard" planning and operation computer models could make valid estimates of the economic impacts. Reliability assessment may be more judgmental.

Reliability - No, not accurately. However, using load flow and transient stability programs, a reasonable value may be obtained. Economics - No, not accurately. However, using unit commitment and production costing programs, a reasonable value may be obtained.

Models are Unit Commitment, Promod III, Proscreen II, and TIGER for generation, while load flows and transient stability programs developed by Power Technologies, Inc. are required for transmission.

Expertise required includes knowledge of the above models, experience in utility operations, reserve policy, reliability obligation, probability assessment and risk assessment.

is not aware of any single program which includes all of the characteristics noted above and which specifically focuses on "less central coordination". The term "less central coordination" can have several meanings. Existing reliability/dispatch programs, power flow and stability programs, multiple sensitivity analysis, and practical engineering judgement could be used to estimate the reliability and economic impacts of having versus not having the characteristics listed in questions 17 and 18.

QUESTION 21

OTA'S SCENARIO 3 INCLUDES ALL SOURCE COMPEITION FOR NEW BULK ELECTRICITY SUPPLIES WITH MARKET-BASED PRICING. IF COMPETITIVE BIDDING WERE ADOPTED FOR NEW POWER SUPPLIES WITH UTILITIES DETERMINING THE NEEDS AND PREFERRED LOCATIONS AND SOURCES, WOULD YOUR UTILITY WANT TO COMPETE IN THE BIDDING FOR ITS OWN NEEDS? WOULD YOUR UTILITY WANT TO COMPETE TO SUPPLY GENERATION IN OTHER UTILITY SERVICE AREAS?

Response:

The Company's position in regard to competitive bidding in bulk power markets (as specifically described in the FERC NOPRs of March 16, 1988) hinges upon pivotal, but troublesome aspects of the kind of bidding programs mentioned. The Company does not believe that the injection of competition and bidding into the generation segment of a integrated electric system comports with the letter or the intent of the Federal Power Act (FPA) as it now exists. Further the Company agrees with the rationale against such competition as adopted by the framers of the FPA as the basis for the law as it now stands.

Possible legislative changes in the FPA and Public Utility Holding Company Act (PUHCA) notwithstanding, the Company also believes that the bidding proposal will ultimately lead to antitrust litigation whether the utility participates or not.

The scenarios attached to this questionnaire and the proposed FERC rules would condition utility participation in the bidding process by mandating open access to the transmission system. This condition would most likely be unacceptable to the utility and could effectively preclude willing utility participation.

Given the huge uncertainties as to the eventual appearance and character of a bidding program, the Company does not believe that unqualified answers to these questions can be given. The decision of whether or not to participate in a bidding program would depend upon the conditions and risks the Company would have to accept in order to participate.

The Company would certainly maintain that it has the right to serve its own load, and by virtue of its obligation to serve, has the right to participate in the economic growth of the area it serves. However, our desire to participate in meeting the needs of our customers could effectively be precluded by the form and structure of the bidding process.

We would bid, through a subsidiary, for new power supplies both within our service territory and in other utility areas. We would not bid as a utility in our own service area, we would reserve capacity to be built by the utility for reliability, fuel diversity, and other system reasons.

We would want the option to be able to compete in the bidding for our own needs. The Company has not developed a position regarding any desire to compete to supply generation in other utility service areas and would need to evaluate on a case-by-case basis.

Competitive bidding formulas cannot adequately reflect all non-price factors for all utilities or for a given utility at all times. Still, if competitive bidding is adopted, utilities should in no way be precluded from participation on an equitable basis.

Maybe--We would have to examine the situation and evaluate the ramifications (financial risk, transmission access, etc.) of participating in competitive bidding procedures.

Yes, we would want to compete in the bidding for our own needs and to supply the needs of other utilities. However, if such bidding to supply the needs of others would require transmission access conditions, such as the proposals for "wheeling in" and "wheeling out", this would present a disincentive to the bidding process.

We would definitely want to be a bidder for meeting our own needs. Other entities can bid on our need under existing regulation. If other utilities could bid on needs in our service territory, we would certainly not want to be constrained by any form of restriction such as the 35 Act to preclude our Company from being able to compete in others area. A proper balance of deregulation on a regulated industry will be difficult to achieve.

would want the flexibility to bid on its own needs. Under current legal limitations, would probably be unable to compete for supply in other service areas.

We would bid on our own needs. We would bid on neighboring areas to the extent we could in effect build joint units.

In principle, Company does not believe mandatory bidding is universally appropriate. However, question is answered in context of such obligation. Yes, with the company retaining the obligation to serve, it will be imperative for the company to attempt to secure the right to serve. Our company may choose to compete to supply generation to other utility areas depending upon how the competitive bidding program would be structured.

(1) Yes, would want to compete to provide its own needs.

(2) would likely consider competing to supply generation in other service areas.

It remains very unclear what sort of bidding program could be implemented for use between control areas which would not jeopardize the benefits derived from the coordination now practiced by regional utilities. Additionally, the conditions imposed for the right to bid may be unacceptable. For these reasons, the Company cannot make a judgement at this time concerning the advisability of bidding for load outside of our existing service territory.

It is unlikely that the State Commissions which regulate the four Operating Companies will require them to adopt all source competitive bidding for new bulk power supplies. However, if such an event does occur, would probably have to seriously consider how it could compete with third parties on an equal basis. This could include an unregulated subsidiary which has the same financial flexibility as third party bidders or bidding traditional rate base facilities, whichever proves most cost effective. has no plans at present to bid on projects in other service territories.

21. does not endorse Scenario 3; but, if it is implemented, will demand the right to provide to its electric customers continued access to the design and construction expertise that has developed over the past 46 years, which has resulted in being a low cost producer. If competitive bidding is adopted, would want to compete in bidding as an IPP to supply generation in our own service area, as well as in other utility service areas.

Yes, under the simple conditions described above. No, under the detailed conditions described in the scenario.

21. If bidding for new power supplies were adopted, . would definitely want to compete in the bidding for its own needs.

SRP has established a policy against building power resources to supply the long-term needs of other utility entities. We do supply others on a short-term (five years or less) or non-firm basis only.

Yes, for its own needs and for the needs of other utilities, particularly those adjacent to its service area.

21. would want to compete in the bidding to supply its own needs and would argue strongly to preserve its existing right to do so. Under certain circumstances, also would want to compete in the bidding to supply the needs of other utilities.

Yes to both questions within the limits of our legislative mandate, i.e. the .

We would want to compete in the bidding for our own capacity needs. That would assure us of supplies at least as economical and reliable as we can provide ourselves. We may wish to compete for supplies in other areas if we have the necessary resources to do so and the risk/benefit relationship is attractive.

Yes.
Maybe.

QUESTION 22

OTA'S SCENARIOS 4 AND 5 ENTAIL SUBSTANTIALLY RESTRUCTURING THE POWER INDUSTRY BY SEGRAGATING A COMPETITIVE GENERATING SECTOR FROM TRANSMISSION AND DISTRIBUTION. WHAT OPERATING AND PLANNING PROBLEMS WOULD HAVE TO BE SOLVED BEFORE THE UTILITY COULD SPLIT GENERATION FROM TRANSMISSION AND DISTRIBUTION? FOR INSTANCE, WHAT WOULD HAVE TO BE IN CONTRACTS BETWEEN GENERATION AND TRANSMISSION COMPANIES TO ENSURE THAT DISPATCH WOULD OPERATE AS RELIABLY AND ECONOMICALLY AS IT DOES NOW?

In order for dispatch to operate as reliably and economically as it does now, utilities would require the same control over third-party generators as ownership provides for existing units. Without ownership, utilities will lose some control over third party units with a potential loss of economy and/or reliability. It is conceivable (but unlikely) that utilities can negotiate contracts with third parties which provide for a predetermined capacity payment but the fuel supply, operation and maintenance of the third party unit remains under the control of the purchasing utility. In essence, the utility would be leasing a generator rather than buying one but all Scenario 5 and competitive bidding becomes under this arrangement is a different form of financing new construction. This form of financing is available to utilities today, without the added complexities of bidding, where utilities enter into a sale and leaseback arrangement with outside investors.

Utility electrical facilities were designed to vertically integrate, in the most reliable and economic manner, the three functions of distribution, transmission, and generation. A conflict of goals will exist between the Disco (operating under cost of service regulation), and the Genco (charging what the market will bear). The divergence of goals allows miscoordination of these facilities to occur,thereby insuring inefficient and uneconomic utilization for the customer. Thus, not only must operating and planning processes solve traditional electrical system problems, but a myriad of new problems created by artificial constraints, contract inflexibilities and changes in the national energy situation must be addressed. These factors obsolesce the key assumptions and parameters on which the contracts were based.

There are too many potential problems and questions to be addressed here.

It is suggested that OTA review the comments of various parties on the

FERC Bidding and IPP NOPRS to get a view of many of the issues.

It is · opinion that segregating a competitive generation sector from the transmission/distribution sector(s) would result in an inefficient and unreliable supply of electricity. The planning and operation of these segments must be coordinated. The planners and operators must be operating under the same agenda and that agenda is the obligation to serve. Coordination and the obligation to serve are necessary to achieve the overall efficiency in planning and operations that are in the best interest of society.

As such, the necessary contract provisions to ensure reliability and economy would be so all pervasive that the generators would have to virtually cede operational control to the transmission/distribution entity. This level of control must be essentially the same as is currently exercised by utility control centers.

An example which illustrates the need for central control is the simple case where one of four parallel transmission lines from a power plant is suddenly faulted. The plant's output must be reduced very quickly to maintain stability on the remaining three lines. The ability to immediately reduce the plants output prevents a potentially more serious threat to security of the system.

This same example can also be used to illustrate a point on economics. If two plants are on the same lines, it would be more economical to reduce output at the plant having the higher operating costs. If one plant is a peaking plant burning high cost oil or gas and the other plant is a nuclear plant, the potential cost savings could be significant. Up to the minute operating costs are needed by the dispatcher in order to make the correct decision so quickly.

If the plants are independently owned, then neither owner would want their plant's output reduced at the expense of lost revenues. This one example of a transmission line fault could be expanded to include the case where both plants are operating under "take or pay" contracts; or the case where many small plants are on the same line and several of these would have to be taken off-line; or the case where no control of dispatch is possible. There are probably many other situations that a

dispatcher might face for this one simple case of one transmission line fault. However, this simple example illustrates why it would be virtually impossible to foresee all the possible events that could require dispatch decisions and then incorporate adequate provisions in contracts to cover all possible events.

Some of the more obvious considerations that would need to be addressed in contracts are the following:

- Location of new plants
- Size of new plants
- Construction schedules for new plants
- Fuel types
- Regulation and voltage control specifications
- Reliability specifications
- Full economic dispatch
- Maintenance scheduling
- Right to audit facilities and compliance with specifications
- Availability of real-time operating and cost data
- Security dispatch

We are vertically integrated and believe this approach lends itself well to the establishment of uniform corporate goals and reasonable overhead costs. A deviation from this form would require a substantial amount of study which must review the effects on reliability and costs. Contracting for bulk power generated by others on a long-term basis would, in our judgment, be an impossible task. It would be almost if not impossible, to cover all items in a contract. The changing conditions surrounding long form contracts would suggest economic re-openers or litigation which would make projections extremely difficult and place reliability in limbo.

Relative priorities among differing T&D's served by a single generator and among differing generators serving a single T&D. Also compatible priorities for generation and transmission. How to allocate operating reserves, generation span vs load shedding.

Response: Economic risks would have to be negotiated and distributed in a manner all parties could accept. Items for consideration include:

(1) Pricing mechanism for the power delivered to the transmission company.

(2) Some guarantees regarding minimum delivery and minimum takings.

(3) Arrangements if power is not available from GENCO.

(4) Who has first right to GENCO power if GENCO is supplying several parties.

(5) Where is service provided? Who pays for switchyard development and upkeep?

(6) General contract terms such as length of contract, etc.

Complex procedures would have to be put into place to provide for identification and curtailment of all interchange transactions during heavy loading conditions. Mechanisms would have to be available to identify, in real time, which transactions created which problems.

Transmission systems are not in general planned to operate for all possible generation scenarios. To do so would be economically unwise. Therefore, some constraints would be necessary on the generation system to ensure that reliability is maintained. For example, on the present system minimum levels of generation are required at for peak conditions. Also, at both minimum levels and maximum levels are established for different load levels and magnitudes of power transfers to and from

Company believes disaggregation of vertically-integrated utilities creates economic and reliability, as well as operating problems that cannot be cured contractually. Also, see response to Question 23. (Transmission companies would need legally enforceable provisions assuring that the generating company would use the transmission company's plant in a specific way (or set of ways) which had been agreed upon prior to the execution of such a contract.)

Scenarios 4 and 5 contemplate the segregation of the industry into generation companies, transmission companies, and distribution companies. Distribution companies would be subject to state regulatory jurisdiction and would have an obligation to serve. Distribution companies would contract with generation companies for their capacity and energy supply needs and would contract with transmission companies for their capacity and energy delivery needs. These arrangements would have to clearly define the contractual obligations of the providers of capacity and energy, and transmission service in order that the regulated distribution company can fulfill its statutory obligation to serve its customers. It is highly unlikely that terms and conditions could be designed for Scenario 5 which would result in the levels of reliability and economy which exist now.

Priorities for transmission use would have to be established, including curtailment of generation during contingencies. Would still need central control to make sure contracts not violated, probably require stiff penalties for non-compliance which could jeopardize the whole network.

The distribution companies would need to maintain as much control over their sources of supply as possible. Ideally, the same level of control could be achieved through contracts as through ownership. Contracts could include provisions for maintenance scheduling, economic dispatch, availability,

The operating and planning problems would be extremely complex, and it would be difficult to contractually duplicate reliability (under identical criteria) required by a utility's obligation to serve.

We would have to address: "control" of units; have input into maintenance scheduling; be assured of adequate reserves and back-up; define performance standards and penalties for failing to meet such.

22. Question. OTA's Scenarios 4 and 5 entail substantially restructuring the power industry by segregating a competitive generating sector from transmission and distribution. What operating and planning problems would have to be solved before the utility could split generation from transmission and distribution? For instance, what would have to be in contracts between generation and transmission companies to ensure that dispatch would operate as reliably and economically as it does now?

Answer. There are a substantial number of operating and planning problems that will need to be solved. Most of these issues could be handled contractually by requiring generators to meet operating standards. However, because of their different motivations it is uncertain whether contractual agreement will always assure that all generation entities will operate according to rules prescribed by the transmission company. Some of these requirements include certain operating capabilities and protective devices on the generators (var output, power system stabilizers, frequency and voltage control), increased communications to the dispatch center to allow dispatching of the appropriate generator's power to its contracted customer, means of allocating spinning reserve, load following dispatch, and ability to disrupt service for certain system conditions. The transmission company would need to control unit commitment and dispatch, and generation entities would have to be responsive to the transmission company's direction. Existing systems used to monitor transactions could require substantial modification to handle the many possible generation entities. Another issue to be resolved involves priority for economic sales to others during non-peak load time, particularly when transmission capacity is limited.

For planning, some important issues include maintaining adequate system stability when units are sited with only plant economics in mind, time constraints getting new transmission capacity for a new unit or direction of wheeling, and appropriate rates to assure recovery of all new transmission investments for a wheeling transaction during the contract period. Also a regulatory agency approved standard for transmission reliability/capacity will be needed.

22. Utilities and others are interconnected today at various voltages and interconnection points. We simply provide metering at the appropriate locations such that actual flows can be compared with scheduled flows. Additional metering may be required to provide for a generation/transmission-distribution split.

For safe, economical and reliable operation, generation and transmission-distribution operators must remain in close contact. A significant amount of coordination is required to provide the proper transmission and distribution configuration to accommodate generator operation.

Numerous planning problems are presented by both Scenarios 4 and 5, in comparison with today's coordinated system. Perhaps foremost is the requirement to coordinate generation additions with corresponding additions to the transmission system. Both generation and transmission planning require long lead times. These Scenarios are envisioned to further lengthen the lead times required for construction, exacerbating the present forecasting/planning/construction lead time situation.

Issues that have to be resolved include the degree of control by each party in the areas of unit commitment, maintenance scheduling, hour-by-hour dispatch, unit performance criteria and expenditures related to the unit performance. It is doubtful that existing reliability and long term economics can be maintained by contract enforcement of extremely complex operating relationships between generation and system operations.

Restructuring may not be readily applicable to due to our legislative mandate. From a generic technical perspective, attention would need to focus on operating and planning criteria because in : State the generation and transmission systems are integrally operated and planned on a coordinated basis, including maintenance scheduling, allocation of operating reserves, sharing of economic dispatch benefits and participation in installed reserve agreements. From a contractual standpoint, documents would need to be put into place to retain the regional reliability councils and Pool coordinated operations in a format that ensures that the reliability and economic benefits gained in the past from this industry structure are continued. Also, because several generating projects were licensed together with associated transmission facilities by both Federal and State jurisdictions, legal obstacles may be difficult to hurdle to separate the transmission function from these generating projects.

At a minimum, a T&D utility would want contractual arrangements which would permit it to utilize its contracted generating resources in the most economical manner. It would also want the ability to coordinate, among various suppliers, unit outages for maintenance, refueling, etc. In addition, it may be necessary for such a utility to have some control over operating, maintenance, and facility upgrading decisions in order to assure reliability of generation resources. It would also be desirable for the utility to have the right to assume complete control over generating facilities in the event the facility owner is unable (due to inadequate financial resources or for other reasons) to operate it on a reliable basis. Without the foregoing contractual protection, reliability of service could be seriously jeopardized.

This list cannot begin to cover all the problems. The contract would try to establish complete coordination between two separate companies with possible very different objectives to ensure that dispatch would operate as reliably and economically as it does now with only one company. The following are examples:

- minimum load generation may not match T&D load obligation.
- Generation voltage requirement may not match transmission voltage which in turn may not match distribution voltage.
- Maintenance scheduling of generation and transmission.
- Fixed payments to generation companies for:
  - Current return on their investment.
  - O&M costs.
- T&D company obtains dispatchability of generation company resources.
- Location and timing of new capacity.
- Generation company must have obligation to purchase and/or build sufficient resources to meet T&D company's future needs. A solid link between obligation to serve and supply must be maintained.

The planning and operation of a power supply system, in terms of the generation, transmission and distribution functions, must be carried out in a totally unified and integrated fashion in order to assure reliability of supply to ultimate customers. Since the nature of electricity supply is instantaneous from the generator to the ultimate user, control over the entire process must be instantaneous and continuous. To segregate and treat each function as independent entities, such as GENCOS, TRANSCOS and DISCOS as proposed in Scenario 4 and 5, would imply an externalization of the many internal relationships inherent in power supply systems, many of which cannot be readily externalized, and attempting to deal with these through some form of contractual arrangement.

In such a system of segregated entities, the planning of facilities to meet future requirements would be dependent totally on some form of contractual coordination among independent entities, which is bound to introduce a high degree of uncertainty as to whether adequate power supply facilities will be available to meet the requirements of customers. The matter of obligation to serve could no longer exist since the DISCO -- the supplier of ultimate customers -- would have no responsibility and control over the delivery and supply facilities. Regarding the many dynamic operational control functions such as economic dispatch, load frequency control, reactive supply and system stability, which are an inherent part of the overall power supply system, the externalization of these into some form of contractual relationship is questionable, and is bound to lead to a lower level of reliability and economy in power supply than exists in the present system.

22. In order to satisfy the mandated obligation of the distribution sector to provide reliable and economical service to its customers, contractual arrangements with the transmission and generating sectors must include resolution of the following items before generation could be segregated:

Operating

- Require interconnected operation of transmission systems with central dispatch to provide reliable and economic commitment and continuous dispatch of all available generating resources, including power sales to and purchases from other interconnected systems.
- Daily analysis of generation and transmission systems for line loading and stability.
- Coordination of emergency procedures.
- Coordination and scheduling of generator and transmission maintenance outages.
- Pricing of power supplied and billing procedures.
- Maintain adequate generation reserves, both in amount and location, to assure supply reliability.
- Provide and maintain adequate communication facilities.
- Provide adequate training of central dispatchers.

Planning

- Make studies to demonstrate adequacy of supply resources and transmission system to meet the power needs of the distribution sectors supplied by the interconnected transmission system for at least a 10 year future period.
- Financial penalties for supply deficiencies.
- Evaluation of all possible generating resources for future additions, including transmission requirements.
- Contracts with other generating sectors to provide adequate reserves.
- Commitments to meet the lead-time required to install new generating resources and transmission additions.

Question 22 raises very complex issues and our answer, while attempting to be responsive, should not be construed as comprehensive. Many additional issues requiring resolution are likely to surface should such major restructuring of the power industry occur.

QUESTION 23

IS THERE A SIGNIFICANT DIFFERENCE IN TECHNICAL FEASIBILITY BETWEEN WHEELING POWER GENERATED BY A) ANOTHER UTILITY; AND B: AN IPP OR QF? IF SO, WHAT ARE THE DIFFERENCES?

Differences would result if IPPs did not adhere to the following rules as detailed in attached NERC document, "Reliability Considerations For Integrating Non-Utility Generating Facilities With Bulk Electric Systems", particularly Items 2 and 3, pages 21-25.

There can be technical differences between wheeling power generated by another utility and an IPP or QF. Since most utilities are interconnected at multiple points on the bulk transmission network, the effect of wheeling is not at a single point. An IPP or QF may be located at a weak point on the sub-transmission system and the addition of a large generation unit can result in significant reliability problems even though the capacity of the transmission system is not exceeded.

A philosophical difference also exists. The utility strives to balance between reliability/security and economics while the IPP and QFs emphasis is on economics only.

The primary differences are not who is generating the power to be wheeled but how that power is planned, designed, coordinated, operated, dispatched, etc. with respect to design and operating criteria. In most cases, wheeled power does not flow 100% on a defined electrical path so explicit contracts are required, especially for IPP's and QF's who do not participate in coordinated design and operation of the bulk power system, to ensure that the bulk power system is operated reliably.

There need not be any difference in the technical feasibiltiy provided that an IPP or QF operate under the same operating practices and procedures that utilities now adhere to. As more players are added, the coordination and control complexity increase, significantly requiring more sophisticated communication systems, EMS's, and technically trained operators.

23. Our response to question 19 stated that IPPs 50 MW or larger would be required to have the characteristics listed in questions 17 and 18 and, consequently, would respond to central control and economic dispatch. If an IPP met such requirements, then the impact of wheeling its output would be essentially similar to wheeling power generated by another utility. Both options would be limited by system transmission constraints. The wheeling of power from either source may impede or prevent the economic dispatch of other available generation.

Since, as stated in the response to question 19, QF output is controlled only in emergencies, wheeling such power could have significant adverse impact on economic operation if it precluded transfer of more economic power.

23. An IPP or QF is generally interconnected with a utility at one point on the system. Wheeling power generated by the IPP or QF is dependent on the facilities where a single point of failure could open the wheeling path. Utilities are generally connected at multiple points, providing for improved reliability.

QFs also generally interconnect with the utility system at 12 KV, so the power generated must go through the utility distribution network. The utility thus has customers connected to a generator over which we have no control, presenting safety and reliability problems. Inter-utility interconnections, in contrast, are generally at the 69 KV level or above, avoiding such difficulties. Therefore, one difference is the reduced ability of the wheeling agent to guarantee reliable service.

An IPP or QF, especially in smaller sizes, may operate unmanned, whereas utility personnel are on the job 24 hours a day. Should a system problem develop, utilities will take immediate action. Response by an IPP or QF will depend on travel time, etc.

Answer. Wheeling power for another utility, or an IPP or QF is similar as long as the IPP or QF generator operates according to the same prescribed rules as utility generation. For example, the entity called upon to wheel would need the ability to call for an IPP or QF generator to be backed off if the transaction was causing a problem on the transmission system. There is concern that this type of control, while technically feasible, could be harder to maintain when a transmission company is dealing with many generation entities. Other concerns would arise if AC-DC conversion is involved or the actual output of an IPP or QF is variable based on the way it produces power (wind, for example)

Yes, there are considerable differences:

1) Utilities are responsible for maintaining control area supply/demand balances. Capacity outages with each utility can be quickly made up by that utility's spinning reserve. An IPP or QF typically has no reserve, so the wheeling utility has to provide spinning reserve for the IPP or QF.
2) Sheer number. There are only a limited number of utilities that may participate in bulk power transfers. It is both easy to schedule a limited number of transfers and to assess their effect on the performance of the network. IPPs and QFs may consitute an unmanageable number of sources, both to schedule and assess impact.
3) IPPs and QFs may not provide adequate reactive power supply to support the MW output, burdening host utilities.
4) IPPs and QFs may be located in such a manner as to produce significant detrimental impacts on transmission loadings. During emergency operating conditions, the controllability of IPPs and QFs is questionable, therefore requiring the host utility to operate its system in an uneconomic manner to preserve reliability.

Probably not if the utility, IPP, or QF meets NERC and Power Pool interconnection and operating standards.

An IPP, QF or another utility presents the same technical issues with respect to wheeling.

All current NUG is done pursuant to a contract with the utility retaining control over power flows. Many of these arrangements are interruptible in nature by the utility. Those few which are viewed as firm are modeled into the system planning process and if new construction is required to accomplish this firm commitment, it is paid for by the parties receiving the benefit.

Power generated by another utility in order the control of that utility and can be ramped up or down as required. Telemetered data is instantaneously available to provide unit status, etc. NUG capacity is typically small in size and not easily regulated due to the economies of scale-

Yes, wheeling service provides for things in addition to just wheeling KW's. Other factors are voltage regulation, load following, reactive flow, emergency power, and operating reserves. These are handled well in the current utility-to-utility environment but are unknown quantities when dealing with NUG's.

23.
Yes, utilities employ Automatic Generation Control (AGC) equipment to effect power transfer between control areas. AGC equipment controls the interconnection frequency, time error, and tie line power flow regulation. Most IPPs and QFs rely on utilities for regulation, thus increasing the utilities' operating burden and cost.

does not foresee a technical feasibility difference in wheeling power for a utility or a NUG. However, without substantial NUG wheeling experience, can only conjecture and offer the following comments and concerns:

- NUG decision-maker for operations not always available.

  Normally utilities maintain a well qualified staff 24 hours a day to handle problems as they occur. This may not be the case with NUG's which may force the NUG's to make judgmental calls concerning dispatching and accounting procedures that it is not presently staffed or trained to make.

- Economic dispatch distortion from NUG generation.

  One of the major economic benefits to regional consumers is a utility's ability to do economic dispatch. As NUG's proliferate in a service territory of a utility, the NUG portion of generation is removed from economic dispatch consideration even if it is the highest cost generation in the region. Most NUG's will have independent sales contracts associated with its resource that will prevent the utility from ever shutting it down for economic dispatch reasons. This could present a deterrent to power industry competitiveness, and inhibit an industry-wide movement toward more efficient operations.

- NUG non-participation in maintaining system stability.

  During times of main grid instability, a utility may shutdown some of its resource generation to regain control. A NUG would lose revenue if its plant was taken offline. What legal recourse would a NUG have if it felt the utility could regain control by shutting down more of its own generation? What protection would a utility have?

- NUG non-participation in providing required transmission.

  When marketing a firm power resource, a utility cannot rely on another utility to construct increased capacity in its transmission system to wheel that power. Usually another utility will only wheel power over its system when that system has surplus capacity to its needs. If that utility does not have surplus capacity in its transmission system, another utility cannot force it to construct additional capacity to wheel its firm resource load.

  Usually utilities will jointly construct transmission lines to meet their individual requirements. However, NUG investors will not always be inclined to participate in transmission construction nor will they have the necessary authorization to obtain right-of-way through condemnation procedures over private and public lands. Congress may wish to address this and the other aforementioned problem areas if it proposes to encourage NUG construction without requiring the NUG's to accept utility marketing responsibilities.

- Area load control.

  Typically, other utilities generation for load is dispatchable and can be counted on to contribute to meeting control area performance criteria. Conversely, NUG's are normally generating as allowed under

Yes. Wheeling power generated by another utility typically presents less of a technical challenge than wheeling for a NUG. There are a limited number of interface points between utilities. Inter-utility connections are established based on long-term planning and coordination arrangements. Generation supplied by a utility tends to be more stable because of the utility's overall system generation capability. Because non-utility generation typically lacks back-up capability, loss of that supply source could affect the wheeling utility's power supply. Further, utilities that operate nuclear units have a special concern for the stability of the transmission system. Instability in the power grid could degrade off site power supply required by nuclear units.

The open exchange of information among the nation's utilities including projected load, generation stability, and other matters affecting the day-to-day system operation as well as long-term system planning contributes to the high level of reliability now enjoyed. This high level of coordination can not be achieved with an unlimited number of interconnections between the transmission system and generation sources. Further, interconnection between utilities tend to be established at points that will take advantage of the natural directional flow of power.

There are natural economies associated with a vertically integrated electric utility system. A move toward increased wheeling for NUGs would reduce the amount of vertical integration and increase the coordination and control obstacles faced by the transmission system. The addition of each power supplier to the transmission system increases the number of possible planning scenarios by exponential magnitudes. Because of the relatively small capacity typically provided by IPPs and QFs, the cost of providing wheeling is disproportionately high.

Yes, there is a difference since the utilities are in direct communication with each other and so can adjust more quickly. Utilities continually contribute to the overall reliability of the electric system by building transmission for emergency conditions, dispatching for security reasons, maintaining spinning reserve, etc. Wheeling costs for utilities and IPP or QF should reflect this difference in contribution to system reliability.

Planning: load forecasting would become more uncertain since require-
ments and large industrial customers could easily move off system.
Similarly, customers on other systems could elect to join the
system. Estimating requirements for fuel, high voltage transmission,
and additional generating capacity would be made more difficult.
Operations: would probably require new (very complicated) computer
program and additional personnel to monitor system operations.

GENERATION PLANNING CHANGES: Continued erosion in the linkage between obligation-to-serve and the opportunity-to-serve will result in peaking type capacity additions which are less capital intensive, shorter lead-time capacity additions which are also less efficient.

TRANSMISSION PLANNING CHANGES: A significantly stronger grid would be required. The current utility practice of rescheduling generation sources at times to resolve grid problems would probably no longer be workable. Additionally, if the utility were required to build lines for retail wheeling by others, there would be legal questions of the applicability of eminent domain rights in the acquisition of right-of-ways.

GENERATION & TRANSMISSION MAINTENANCE: Unless all generation sources were under control of the utility, maintenance of the transmission facilities would require much greater coordination with other parties. Coinciding maintenance outages on adjacent or nearby plants would be more difficult to plan if continued service to that area relied upon transmission imports.

Planning would become much more difficult due to the many uncertainties.

There can be a difference, depending on the method of scheduling and the degree of control. Normally, wheeling between utilities is by mutual agreement, based on the uses and benefits determined by engineering studies and judgment. An IPP or QF may not have incentive for mutual action, but only interested in wheeling when it is necessary for them. This could occur at a time when it is not beneficial for the utility to wheel for a QF or IPP. However, if the wheeling arrangement is properly defined, there should be no technical difference between wheeling for another utility, an IPP, or a QF.

has worked with other utilities in the ERCOT system for years and has established a high level of confidence that other ERCOT utilities share concern for proper voltage coordination, frequency control, time correction, power transfer limits, and system reliability. For example, neighboring utilities will often change their dispatch in order to help another utility get a unit online or keep a unit online during low load periods.

Other utilities in will also alter their dispatch to relieve overloads on critical transmission facilities. In general, a top priority among utilities is to protect the system reliability by keeping it intact and preventing cascading outages. is concerned that an IPPs priority scale may not rank reliability as a top priority objective. If so, serious technical problems may arise. For example, improper coordination of voltage control, frequency control, or generator output levels could amplify certain disturbances and lead to cascading outage conditions. If an IPP (cogenerator) is determined to make a sale "no matter what" lines could be loaded to the point that a single contingency would cause them to overload and trip. Also, utilities may not be able to bring on local generation needed for system security because IPP's refuse to back down to allow the must run unit to reach minimum load. In the worst scenario, wheeling for IPP's could weaken or bring to an end the spirit of cooperation that exists between utilities making up the NERC reliability regions. Traditional operations philosophies may then be replaced by a philosophy of "every man for himself" in which overall system reliability would deteriorate rapidly.

QUESTION 24

IS THERE A SIGNIFICANT DIFFERENCE IN TECHNICAL FEASIBILITY BETWEEN A) WHEELING FOR RETAIL CUSTOMERS; B) WHEELING FOR WHOLE OR PARTIAL REQUIREMENTS UTILITIES WITHIN YOUR CONTROL AREA; AND C) WHEELING FOR UTILITIES OUTSIDE YOUR CONTROL AREA? WHAT ARE THE DIFFERENCES?

The technical difficulties are more related to the potential number of transactions and to the characteristics of the load to be wheeled rather than the corporate structure of the sending and receiving parties.

Utility to utility wheeling can usually be accomplished with minimum difficulty. The number of transactions to be wheeled by any one utility is likely to be small. The necessary metering and control equipment is usually available. The characteristics of the load to be wheeled can be readily described and is predictable. The capability of the system to handle the wheeled load can be evaluated relatively easily using the same general approach as for other transactions. Planning and operation can generally be accomplished by experienced personnel using established procedures.

In contrast, retail wheeling has the potential to involve a relatively large number of locations. While the required metering and control equipment could be installed at each individual location, it is less clear that adequate coordination could be accomplished if a large number of transactions were involved. For example, planning studies would have to consider the effect of all reasonable combinations of transactions -- recognizing that all transactions may not be in effect at the maximum level each day. Operators must be able to predict variations in daily and hourly loading and must have the authority and capability to respond to abnormal conditions.

Yes, there are significant differences between retail wheeling and wheeling for utilities outside the control area. First of all, it must be clearly recognized that the retail customer connected to its franchised utility has no control capability to cause wheeling to take place. When retail wheeling takes place -- which is a misuse of the term "wheeling" -- the franchised utility redispatches its generation so that the amount of "wheeling" power can be imported into the utilities' control area from another control area. In reality, such "wheeling" is simply a generation displacement service between two utility control areas whereby the retail customer has attributed to its account the benefit of the transaction. From a technical standpoint, the retail customer, being electrically connected to the franchised utility, continues to receive from the franchised utility all of the services which are inherent in its electric power supply -- reactive supply, stability services, spinning reserve and reliability of supply. As a result, the franchised utility continues to bear the burden of reliably supplying the retail customer even though the franchised utility's generation that was dedicated to the supply of the retail customer has been displaced. The corollary question also arises as to obligation that the retail customer should bear regarding the investment in the generation that is stranded, generation that was constructed to meet its requirements. These same concerns apply equally well to wheeling for requirements customers.

24. For retail customers and utilities within the control area, the host utility does not truly wheel, but instead effectively buys blocks of power contracted by these entities and credits the purchase to their accounts. The host still must deliver capacity and energy from its generators to these buyers to precisely match instantaneously fluctuating loads. Thus the capacity supplied by the host is totally unlike that delivered by the seller. Unless pricing offsets the difference in value of the two types of capacity, the captive customer, lacking financial or political power to purchase externally, would subsidize the transaction. For utilities outside the control area, the facilities of the wheeling utility simultaneously receive and deliver capacity of like kind. The wheeling utility does not have to adjust or control generation to facilitate this simultaneous transaction but is due compensation for the use of its transmission facilities.

Yes. In the case of a & b above, the load of the customer determines the amount wheeled with no regulation or control available. A match between load and wheeled energy does not exist. In the case of C above, utilities outside our control area can regulate to a schedule of energy to be wheeled.

Electrical power does not flow on a discrete electrical path and is therefore not readily traceable from the source to the customer. The bulk power electric system is also operated on a first contingency basis. These conditions complicate wheeling and the determination of transmission capacity available for wheeling. The greater the number of potential transactions, particularly by retail customers or whole or partial customers who do not participate in coordinated operations of the transmission system, the more difficult it will become to accommodate such transactions without affecting reliability.

24. Since is not a control area, we will address only a) and b). One significant difference between a) and b) might be interruptibility. A retail customer might expect uninterrupted service while a utility would likely have alternative supply arrangements. Also, deliveries to retail customer could create transmission loading problems. In either case, the inability of the wheeling utility to control the flow on its transmission could jeopardize system reliability and also could result in non-economic operation to accommodate the power being wheeled.

"Utilities" usually have other sources of supply should a schedule be cancelled; "retail" usually has no back-up source. "Utilities" usually have a control center with which to arrange, control, and complete a transaction; "retail" does not.

24. Providing wheeling services between two parties generally requires that the wheeling entity monitors, on an instantaneous basis, the scheduled and actual energy flow across each interconnection point. The actual flow is telemetered into control centers as needed and meters in the field are read at least monthly to check the telemetered flow. Any difference creates a deviation which must be accounted for.

To provide wheeling for a retail customer, the retail load must be metered continuously and this data must be available to the generating and wheeling entities. The generating entity will then know how much to generate and the wheeling entity will then know how much energy is flowing across its system for that specific load. The metering setup required is expensive; monitoring and providing information on a large number of retail customers who are being provided wheeled energy would be proportionately more expensive as the number increases. occasionally operates units for voltage support. If load is served by another resource, some provisions must be made to provide voltage support and system stability.

For whole or partial requirements utilities, there is generally an agreement with the control area to provide a banking service (this could also apply to a retail customer). In effect, the control area meets the load as it fluctuates throughout a day and sufficient energy is scheduled (may or may not be simultaneously) for the generating entity to cover overall energy consumption. If the wheeling entity did not provide this banking service, the generating agent would have to monitor and generate sufficient energy to serve the load on an instantaneous basis. Still there is some need for banking because of metering error.

Metering and specific arrangements are generally in place to cover interconnection requirements between utilities. Wheeling from one utility to another is technically straightforward from a hardware point of view. It differs from retail, wholesale and partial requirements customers in that the wheeling agent must be aware of opportunity costs or a potential loss of revenue associated with the wheeled energy (i.e. an economy energy sale is terminated because less expensive energy is made available to the purchasing entity as a result of the wheeling provided).

The technical feasibility differences are largely a matter of scale. In many cases there may be sufficient transmission capacity to wheel for partial requirements customers or for other control areas, whereas there would not be sufficient capacity to provide wheeling for all retail customers.

24. From a purely 'technical feasibility' comparison, there are no significant differences. However, all three are not practical unless specific, pre-arranged, wheeling schedules have been developed, and a determination has been made that the transmission system is capable of handling such schedules without limiting or impairing the reliable use of the transmission system for the purposes for which it was planned, designed, financed, and constructed.

Uncontrolled access to a utility's transmission system is not technically feasible if the integrity of the transmission system is to be maintained. By 'uncontrolled' we are referring to a situation where retail customers, whole or partial requirements utilities within the control area, or utilities outside the control area, can arrange wheeling without the wheeling utility first studying the proposed transaction to determine whether it is practical.

Wheeling for utilities outside control area is all done by schedule whereas the other two categories would have to be instantaneous actuals. This means more metering values have to be entered into AGC system for control area boundaries. AGC computer would have to be more sophisticated.

The technical feasibility cannot be separated from the cost and reliability to the customer. Any action taken must be incorporated in long-range plans and evaluated.

Other utilities operate as separate control areas or as a part of a power pool which is a control area. As such, they can meet required performance guidelines such as time correction, area control error, and frequency response. Retail customers cannot perform these functions.

Answer. There could be some technical differences. Wheeling for retail customers generating power requires modifications to the distribution system (protection, switching, metering) if that is where the generator is located.

Presently, specific types of generators are installed and transmission is built from these locations to loads in defined areas. If all customers could shop, transmission would have to be built to allow wheeling from generators located in any direction from the load. Additional transmission would be necessary both locally as well as larger interconnections between regions. Wheeling for utilities outside our control area may contribute more to the need for additional transmission than wheeling within the control area.

Other differences would be in contractual responsibilities of both the distribution customer and the generator, to keep the system operating reliably. However, if the contracts are appropriately written and adequate facilities are available there should be little difference from serving the utility's own loads, if all parties abide by the contract.

Yes. Wheeling is the delivery of electricity from a source entity to destination entity over the transmission facilities of a third entity. Wheeling is accomplished by an increase in generation in the source entity and a concomitant decrease in generation in the destination entity. As retail customers and requirements customers lack generation to decrease in order to accomplish wheeling, the concept is inapt. Also, a means would have to be devised for the remote supplier to follow the destination entity's load with the supplier's generation. Another important distinction is that utility wheeling transactions would tend to be fewer in number and larger in magnitude, making such transactions easier to arrange, implement, monitory, account for, adjust during periods of transmission constraints and control during system emergencies requiring immediate relief.

Yes. Wheeling power for retail consumption involves more access and connection points including telemetering and control hardware. The power flow pattern becomes more difficult to predict and plan for under this situation. The greater level of variation in customer behavior patterns is difficult to plan for on the secondary distribution level. Wheeling to the individual retail customer would involve an unlimited number of planning scenarios.

Voltage support and other control concerns must be addressed when wheeling for Bulk users within a utility's service area. Wheeling for utilities involves a highly coordinated effort with a limited number of connection points. Obviously, the coordination and control efforts are less complicated at higher distribution levels, although any increase in wheeling will require additional telemetering and control hardware.

Wheeling for full requirements utilities, outside of control area, requires technical changes and/or contractual changes with the utility which has load control responsibility in the other load control area in order to provide automatic generation control (AGC) and load following services. The anticipated impact upon if a proliferation of NUG's were to develop and transmission utilities were required through legislation to provide wheeling capacity for the marketing of NUG resources would be increased staffing for dispatching, scheduling, accounting, and billing.

Yes, see response to question 23. In addition, the question of obligation to serve appears unanswered.

24.
Availability, useage, and compensation for distribution line and transformer facilities would need to be addressed in each contract. The wheeling customer's need for stand-by and restoration service would need to be negotiated. Retail wheeling would increase the number of transactions and the associated accounting burden by many orders of magnitude. Wheeling for full requirements customers who assume no control (or responsibility) burdens the utility with responsibility for administering all wheeling contracts on an hourly basis.

Assuming parties (a) and (b) would be taking the same amount of power from the system absent a wheeling arrangement, the technical difference (on the "receiving" end) is that wheeling for another control area represents a change from what would have occurred absent a wheeling arrangement.

The differences depend, in large part, on the location of the load in respect to the generating resource.

a) Wheeling for retail customers may cause the utility to maintain backup reserves should the customers own power source fail. Additionally, if transmission capacity is inadequate to wheel all the customers power, problems could develop in determining priorities for disconnect.

b) Wheeling for partial or full requirements customers encounter the same problems as outlined in (a) above.

c) Wheeling for utilities outside the control area will be limited by the interconnections between the two utilities. In most cases, no generation reserve is required by the wheeling utility.

There can be significant technical differences.

a) wheeling for on-system entities, whether retail or whole or partial requirements, forces the wheeling utility to supply back-up power, ready or not.

b) wheeling for such on-system entities forces the wheeling utility to continue to supply long-range transmission and distribution system planning, regardless of the source of supply.

c) it is not usually feasible for the on-system wheeling customer to supply voltage or reactive power control, both of which have an effective on on-system generation sources.

d) system, area, and power pool security responsibilities become more difficult to assign if the receiving entity is not a control area.

e) wheeling retail customers or for whole requirements customers inside our Control area would require that we provide load following capability. This can only be avoided with sophisticated telemetering and monitoring capability, which actually moves the load to another control area. This problem can also occur for partial requirements utilities if the remote source is not true base load capacity.

f) when wheeling for utilities are outside our control area, the effects are similar to the operation of any generation located outside our control area. Other control areas are responsible for resolving the technical difficulties.

g) as between retail and on-system utilities, retail wheeling could obviously become a larger number of individual transactions. As the number of transactions increase our ability to keep up with paperwork, operations, planning, emergencies, inter-control area communications, and generation dispatch could be completely swamped.

No significant difference between (b) and (c). For (a), retail customers, technical problems arise with metering, scheduling, and control.

QUESTION 25

HOW WOULD UTILITY PLANNING AND OPERATIONS CHANGE IF WHEELING FOR RETAIL CUSTOMERS, REQUIREMENTS CUSTOMERS, OR OTHER INTEGRATED UTILITIES WERE MADE MANDATORY OR STRONGLY ENCOURAGED?

25. If wheeling for retail customers were mandated or strongly encouraged, it could significantly increase the costs to the remaining customers on the system in order to support the stranded system investment. Furthermore, the imposition of mandatory wheeling could require transmission reinforcement not otherwise needed or could advance the timing of planned additions. Major additions could require ten years or more lead time. This would result either in delaying the wheeling or in operating off-economy to accommodate the wheeling with the inherent need to allocate the economic penalty involved. System operation would be impacted by the need to monitor and accommodate the dispatch of the power transfers, which could modify unit commitment and dispatch with cost penalties to the wheeling utility.

25. The most likely customers to pursue retail wheeling arrangements are assumed to be large industrial concerns. Although these customers total less than 10 percent of revenue base, loss of customers would mean that fixed costs would have to be shared by a smaller customer base, resulting in rate increases. Utilities with the highest production expenses would probably experience proportionately greater loss of load and subsequent serious financial difficulties.

It would be very difficult for planners to know when load is going to be lost or added to the system. Effective planning also requires a knowledge of how the system will be used and what the requirements are. Lead time is required to solve problems which are projected to occur in the future as a result of system growth and change.

Operators would be busy trying to determine which loads are actually a part of the system; outside influences would reduce system control. Effectively this could become a technical nightmare

The electric transmission system is very complex, much more so than other industries which have been deregulated. Mandatory wheeling could impose planning, licensing, environmental, construction and operational burdens so severe that it could paralyze and jeopardize the coordinated reliability and dispatch structure presently in place. Caution must be exercised in making changes to the existing utility industry structure to ensure that customer costs are not increased and that the present level of reliability and quality of service is maintained.

Answer. The changes in operations would be in determining how to coordinate the operations and dispatch of all the separate generating entities wheeling on or through the transmission system as various distribution customer's loads change and transmission system elements and generation go in and out of service. Monitoring, billing, accounting and other support systems would become more complex as more entities become involved. Modifications to these existing systems could require significant expenditures. Responsibility for losses would also need to be defined.

Increased flexibility of the transmission system will require additional facilities to be built. Planning would now have to be able to estimate where new major generating sources are likely to be constructed and where the customers for this power are likely to be. This would be for regional interconnections. Otherwise, the planning for wheeling would be the additional local area requirements to reliably connect new generation to the system and to the new loads to allow transfers in and out of all areas. There will probably be a greater need for larger transmission interconnections between regions as most price differences will likely occur between regions. Cost-sharing for the new facilities required, and responsibility for permitting and building them are some additional issues that planning would have to address.

The planning and operation of a system in a reliable manner would become nearly impossible. To properly plan and operate a power system, utilities must be able to exercise control over system loading, voltage support and reliability margins. This is accomplished by planning sufficient transmission to support known supply and demand points and through coordination and ccoperation of bulk utilities. Mardatory wheeling removes this control.

Although we can not cite specific examples, planning and operations will most likely become more complicated and costly and service will become less reliable.

Needed information could be so inadequate and untimely that meaningful planning could become impossible. The host utility would have to attempt to supply the instantaneous demands for generation above the levels wheeled. (See 24 above) That ability is limited by the host utility's responsive generation and transmission capabilities.

Retail customer wheeling of any kind would make utility power supply planning much more difficult, perhaps impossible. No business with capital investment requirements on the scale of the electric utility industry can operate without a system of contracts that limits its risks. The utility's contract is its obligation to serve in exchange for its monopoly franchise. Without that contract, or some reasonable alternative which limits risk, few utilities would be willing to invest in new plants or commit to any long-term supply agreements.

IPPs may be equally unwilling to build unless utilities are willing to commit prior to construction to long-term supply agreements. Thus, the success of any attempt to deregulate or introduce greater competition in electric generation will depend greatly on maintaining the integrity of the distribution monopoly.

It would greatly increase uncertainty of load forecasts, and thus impede least-cost planning; would impact system reliability, and increase the need for additional transmission and generation; would lead to short-term solutions.

We would expect planning to become more subjective and less precise and system control to be more difficult. The greater the number of connections to the transmission system the greater the chance for unplanned interruptions to occur. The number of planning scenarios that would have to be considered would increase exponentially with each new interconnection point. Planning and operations would become more reactive and reliability would suffer.

The effective planning of long lead time, capital intensive bulk electric power supply and delivery facilities presumes a certain degree of predictability regarding the locations, magnitudes and characteristics of the loads which the utility is obligated to supply and the locations, sizes and operational characteristics of the (CONTINUED ON ATTACHED SHEET)

capacity resources which the utility will rely upon to fulfill its obligation to serve. Absent that predictability, efforts to plan the least cost long range expansion will be futile.

Operations would become extremely complex. It is likely that reliability information would be withheld due to the competitive nature of the resultant systems.

If wheeling for retail customers became mandatory, system planning could become very difficult because of the infinite number of potential transactions and arrangements to be studied and considered. From an operating viewpoint, there would be greater difficulty in matching generation to demand if loads in the area were served by others and if the utility served loads in other areas. Accurate determination of the losses associated with the wheeling would be difficult to assess and additional expenditures would be required for metering and telemetering.

25.
Long-term planning of the generation and transmission system would be disrupted. Long-term planning suffers from the accomodation of short-term retail or mandatory wheeling arrangements. If the utility retains the "obligation to serve", costly duplications would be required, including loss of transmission economies of scale. New methods of allocating and assigning costs for distribution facilities would also be required.

There is no way to anticipate this change as suggested without further definition. Both cost and reliability must be considered.

Construction planning and scheduling would prove difficult if customers changed suppliers regularly with short term contracts, thereby requiring different transmission paths. With short term contracts, there is the risk of overbuilding transmission causing costs for transmission services to be very high or the burden for repaying transmission facility costs could fall on others. Where limited transmission exists, competitive bidding by energy suppliers could also increase cost of delivery.

25. If the wheeling as stated in this question was mandatory to the extent that the wheeling utility could not reject a request to wheel--even based on a determination that the transmission system is not capable of handling the proposed wheeling transaction without limiting or impairing the reliable use of the transmission system for the purposes for which it was planned, designed, financed, and constructed--both utility planning, and utility operation of its transmission/distribution system, would literally be in chaotic states. In any event, significant additional transmission plant, and real-time monitoring and control equipment, might have to be installed. Where such additions are not feasible, significant degradation in reliability would most likely result.

Greater uncertainty in transmission planning because "customers" needs would not be known as well. For instance, a price change from the source of the power could change the customers usage patterns and total needs, and the utility providing wheeling service.

If wheeling increased, utility planning would require a study of a much wider range of conditions of generation reserves, fuel supply, and transmission flows. Because of long lead times required for construction of transmission lines, it would be difficult to plan for wheeling in the short term. If a utility planned for long term wheeling but it did not occur, the additional costs of constructing unneeded transmission lines may be passed along to other customers.

Utility operations would become more complex with wheeling by customers. System dispatch would need to be expanded, more real time telemetering would be required, priorities for load shedding would be needed, and complexities of operating the system during emergency conditions would be multiplied.

It is important to realize that most, if not all, power systems have been designed to deliver in a contiguously connected system from generator to load under one central control. In this original scheme of things, interconnections were used for emergency supply and reliability enhancement; more recently for "opportunity" transactions between centrally controlled systems; and only very recently for deliveries of remotely located firm generation. The fact remains that the system design over a 60 to 80 year period did not generally take the latter two functions into account. "Voluntary" wheeling, then has allowed the utility supplying wheeling service to determine if the system would perform a function ancillary to its original function, and contract, or not contract, accordingly.

Base load units would become very difficult to justify. Gas fueled peaking units would become the norm. These peaking units would be low cost, capable of being quickly constructed, but would offer less fuel cost stability. Customers would then be subject to rapid power cost swings due to changes in the fuel markets. The planning process would probably become drawn out. There would be longer lead times between the identification of a need and the actual line construction. Since system planning would become a multi-party process, some lines may not be constructed until after a loss of load incident has occurred. The system would become susceptible to a greater number of outages that could result in cascading and possible system collapse. This type of planning methodology is very similar to a traffic engineer waiting until a serious accident occurs before deciding to install a traffic control signal at an intersection.

Planning would have to take into account the loss of kilowatt-hour sales but would still have to consider capacity for stand-by service. Operations would have to schedule for the wheeling customers in their control area and have to administer an inadvertent account for each one. This would make planning more difficult and less accurate and would increase operating costs.

"Mandatory wheeling" already exists in , for Qualifying Facilities sales to utilities. Further, according to the Substantive rules of the Public Utility Commission the wheeling utility must, with few exceptions, construct transmission capacity to accommodate firm purchase transactions from Qualifying Facilities.

This has happened in an environment where there is little or no economic incentive to accommodate these transactions; indeed a wheeling utility could be required to construct facilities with no assurance of revenue forthcoming of sufficient amount to cover costs. This leaves other transmission customers at risk.

On the contrary, there is disincentive to construct transmission systems. Regulators, legislatures and the public are generally opposed to the siting and construction of transmission lines. Realistic lead times for major transmission projects are now longer than many generation options, such as combustion turbines.

"Mandatory" or "strongly encouraged" wheeling, then changes the basic function of transmission systems. The change in function will necessitate more extensive transmission systems, designed for more general purpose, with more flexibility.

It is also worth noting that the utility required to wheel must know the purposes to which the system will be put. As generation siting becomes an unknown outside the utilities' planning, and as transmission lead times dramatically increase, efficient transmission planning becomes impossible. There are only two possible results; one is that "generic" transmission systems get built that will do most anything they are called upon to do. This means large, complicated and expensive systems. The other result is an inexorable decrease in system reliability.

Load forecasting would become more uncertain. There would be more boundaries to the control area. More study time would be required keeping track of wheeling loads and how they effected system loading and system losses.

The change could substantially impair operating economics and reliability depending on the scheduling and control of deliveries and the degree of backup required of the wheeling utility. Planning would become very difficult for the long term requirements.

QUESTION 26

WHAT CHANGES TO YOUR SYSTEM WOULD BE NECESSARY TO RELIABLY AND ECONOMICALLY ACCOMMODATE ADDITIONAL WHEELING?

The present transmission system was not planned to accomodate additional wheeling and to do so may, in cases, require enhancing the system with additional facilities. Increased wheeling could result in heavier line loadings under normal conditions and thus reduced capacity and transfer capabilities for emergency conditions. Also, transfer capability between systems is often limited by operating constraints as well as the limits of individual components of the generation transmission system. Therefore, to eliminate these constraints and permit a higher level of transfer capability to accomodate additional wheeling, new transmission lines and related facilities may be required.

In general, although some capacity may exist for increased wheeling, would need to build to upgrade transmission facilities to accommodate additional wheeling. Area responses are site specific and require an individual analysis for each new source of energy. Special arrangements would be needed for cost responsibility on any upgrades or new transmissions. Joint regional planning would probably be required.

Very few to handle utility-to-utility transactions. Retail wheeling would be much more complex with unknown implications.

26. Additional sub-transmission system investment to accomodate wheeling contracts would be required. The investment in interconnection and internal transmission would be increased. Additional equipment would be required to restrict inadvertent power flows through the system. All of the above would contribute to significant increases in capital requirements and operating expenses.

Since transmission systems are fully utilized now, additional transmission would be required to accommodate additional wheeling. Also, additional control center computer hardware and software would be required to keep track of the source and destination of each wheeling transaction and to determine network impacts on a real time basis.

The existing economy and emergency transfers already tax the limits of the SWPP transmission system; consequently, new lines would need to be constructed and the economics considered.

More metering, telemetering would be required. Our AGC and SCADA systems would have to be upgraded. Additional recordkeeping would be required to allocate costs to wheeling on our system.

It is not possible to accurately predict the required system changes without a definitive estimate of the required transmission support, the source and destination of the power, the number of inter-connections, and other variables that would be introduced with additional wheeling. Under many possible scenarios additional wheeling could not be economically or reliably accomplished.

Transmission capability would have to be provided to respond to changes made. As discussed in questions 24 and 25 above, responsive generation capability and transmission capacity would also have to be provided, assuming that timely planning information and financial resources were available.

It depends on how much, where power comes from, where it goes, and when.

Some additional wheeling could be accommodated under normal operating conditions with no additional changes since the transmission system was designed to provide import capability during emergency conditions. When contract capacity limits are reached, additional transmission would have to be installed.

GENERATION PLANNING CHANGES: The large load centers in Florida are primarily located in regions where no significant additional environmental emissions are allowed. Wheeling would therefore be of the nature which would add load on the transmission system. Without additional transmission expenses, the choices of future utility generation sites will become smaller.

TRANSMISSION PLANNING CHANGES: Transmission contingency problems which assume a redispatch of generation as a solution may have to be resolved with additional transmission facilities. Since the average size of NUG generation facilities are expected to be much smaller than those added by a utility, there would be a requirement for additional switches and relays to assure safe operation of the transmission grid. The magnitude of these changes would depend on factors such as existing equipment, location of the customer, energy and capacity, and whether wheeling demand was coincident with system demand.

Also, in Florida, the North-to-South transmission grid is normally fully utilized to the point that if only 200 MW of additional wheeling were mandated in this direction, a new 500 kV line would need to be constructed. This would cost some $200 to $300 million dollars.

Some transmission capacity is presently available on the system. Consequently, some additional transactions might be accommodated. Otherwise reinforcements would be necessary. In that case licensing requirements would need to be reviewed and possibly modified (streamlined) to enable necessary transmission system reinforcements to be constructed in a timely manner and to permit retention of coordinated system operation.

Considerably larger transmission reserves would need to be installed across the system to accommodate unplanned loadings that would result from additional wheeling. Considering the uncertainty of the magnitudes and directions of wheeling, it is questionable whether the necessary level of transmission reserve margins could be installed to maintain adequate levels of reliability. Each wheeling request must be examined in terms of the specific conditions that are anticipated on the system.

Answer. The changes to the system will be very dependent on where new generating sources are added and to where the company has to wheel this power. For example the eastern area of our system has already experienced significant problems due to inter-utility wheeling. In this case, major transmission investments would be necessary to accommodate additional wheeling. Methods to determine who would pay for, build, and permit these facilities would need to be developed.

26. The system changes necessary to accommodate additional wheeling would depend on what kind of wheeling would be involved, the generating point and the receiving point, and the load.

Each request would have to be evaluated on an individual basis. Loads up to about 50 MW might be accommodated through certain parts of our system without major hardware changes. Loads over 200 MW would require significant changes. Generally, additional transmission facilities would be needed for the larger loads, primarily at the 230 kV level. These facilities would include transmission lines, voltage and power flow control devices, etc.

The changes to the ? system which would be required to accommodate additional wheeling cannot be identified readily. That is, the required changes must be evaluated individually and would depend on the size and locations of a proposed wheeling transaction. Some additional transactions might be possible with little or no system changes -- e.g. if the wheeling transaction involved power flow in a direction which would tend to reduce loading on critical elements. Other possible transactions might require substantial system changes with a cost in excess of $100,000,000.

Increased metering, communications, and system dispatch computer capacity for monitoring and control would be necessary to accommodate an increased number of wheeling customers. Also, additional transmission facilities may be required.

This would have to be studied with the contemplated wheeling specifically modeled.

26. Required changes, if any, would depend on the location of the source and destination of the power being wheeled. The impact could range from negligible to severe. Should a wheeling request interfere with reliable operation or economic dispatch, required transmission reinforcement could be designed and its cost reflected in the wheeling charges, however, timely reinforcement may not be possible.

System changes would depend on the specific transfer. In some instances, the lowest cost option might be to run the system uneconomically to accommodate a transaction.

Some additional wheeling, under certain conditions, can be accommodated with only minor to moderate changes at this time. However, in a few years, transmission capacity available for wheeling will be limited without additional investment in transmission facilities. Changes to our system necessary to reliably and economically accommodate additional wheeling would depend upon the specific transaction. The changes might include additional generation capacity, additional transmission capacity, additional dispatching, control and metering facilities, and additional personnel. In some cases, it may not be possible to accommodate additional wheeling, either reliably or economically, if the costs would outweigh all possible benefits.

The changes necessary to the system to reliably and economically accommodate additional wheeling cannot be determined without making a study after receiving specific information, such as the location and size of load being wheeled to and the supply source.

Detailed information describing the transaction would have to be known before needed system changes could be identified. For example, if the transaction involved an IPP or cogenerator inside control area, needed information would include the exact location of the generator, size or capacity of the unit, expected capacity factor, megawatt operating range, voltage regulation capability, planned interconnection facilities, etc. Possible system changes include the following:

1) If the IPP (cogenerator) has a reactive capability output that is inadequate, additional "must run" units may need to be brought online to improve system voltages.

2) Additional transmission lines may need to be constructed to relieve overloads if the existing system cannot accommodate the IPP's maximum output levels. Some transmission facilities may be needed to remove the potential for cascading outages due to the loss of a single line or transformer.

3) Additional communication and telemetering facilities may be needed to integrate the IPP into control area.

(Continued)

4) Additional transmission capacitors or static VAR systems may be needed to offset voltage sags caused by heavy loading on the transmission system near the IPP.

5) Power plants may need to be redesigned to refurbished to run at lower minimum load levels.

6) Inductive reactors may have to be installed if IPP's are run at high voltage levels (1.04 to 1.05 per unit) during light load periods.

Our system is now designed around a set of reasonably known facts regarding on-system outages and planned imports from other utility systems. We are presently responsible for generation, transmission and distribution for a known customer mix. We have learned to deal with the uncertainties and predict with reasonable accuracy the <u>overall</u> needs of the system.

Wheeling has had some effects on our system, but as yet has not forced a fundamental change in system design.

As previously mentioned, the added uncertainty of accommodating mandatory wheeling from unknown sources to a steadily changing customer mix will defeat our present approach of constructing only what is necessary, only when it is necessary. The result <u>will be</u> increased cost or decreased reliability.

QUESTION 27

CAN YOU ACCURATELY CALCULATE THE RELIABILITY AND ECONOMIC IMPACTS OF HAVING LESS CENTRAL COORDINATION OF THE CHARACTERISTICS LISTED IN QUESTIONS 17 AND 18 AS A RESULT OF INCREASED WHEELING? WHAT MODELS AND ENGINEERING EXPERTISE ARE REQUIRED?

27. Yes, if sufficient, accurate and detailed data can be obtained. Electrical performance can be calculated by using power flow and transient stability computer models. Economic reliability, and maintenance performance can be calculated using production cost simulation and maintenance planning computer models. Considerable engineering expertise in circuit theory, power system operations and engineering economics is required to accurately apply these models and interpret their results.

has not investigated these impacts.

27. Can you accurately calculate the reliability and economic impacts of having less central coordination of the characteristics listed in questions 17 and 18 as a result of increased wheeling? What models and engineering expertise are required?

Not applicable.

Calculations can be made given good assumptions (i.e., directions, quantities, time frames). Tools to use include load flow, stability, etc. The realibility and economic impacts cannot be accurately calculated. Models must be developed including the capacity, locations, and availability of all NUGs.

No. The North American Reliability Council is presently studying whether or not this can be done. If it can, a model will be developed.

A major study would be required to do this. The results would be valid for only the wheeling assumptions made in the study. Electrical engineering expertise with strong background in power system operation, protection, and design would be required. A working knowledge of engineering economics, and practical experience in its application to power system analysis, is also mandatory. Loadflow, short circuit, steady state and transient stability, and production and transmission costing models would be required.

No

Reliability - No; Economics - Possibly; assuming the generation companies would be willing to make their cost information available which is highly unrealistic in a competitive business environment.

No, we can not accurately calculate the reliability and economic impacts of having less central coordination of the characteristics listed in Questions 17 and 18 as a result of increased wheeling. As for what models and engineering expertise are required, we are not aware of any existing or proposed models that are capable of such estimates. Because the reliability and economic impacts on any one system due to increased wheeling would be different than that for another system and because the impacts on each system would be extremely sensitive to system specific parameters and the amounts of increased wheeling considered, there are no simple or straight forward answers to this multipart question.

For many years, utilities have voluntarily wheeled power for others. The trend has been toward increasing amounts of wheeled power. This has been accomplished without significant adverse reliability or economic impacts on the systems involved. The key is voluntary wheeling. These voluntary arrangements have been entered into with consideration given to established reliability criteria and operating guidelines. The ability of an electric system to use capacity in its transmission facilities to transfer or wheel electricity from one point to another involves good coordinated planning and design. Any significant increase in wheeling if allowed to progress uncontrolled and without adherence to reliability criteria and operating guides (such as NERC Reliability Criteria for Interconnected Systems Operation and NERC Operating Guides) would cause the operation of transmission systems to become so chaotic that not only the reliability of the transmission system but also any economic advantages potentially achieved through increased wheeling could be jeopardized.

Not at the present time.

No, we can not accurately calculate the reliability and economic impacts of having less central coordination of the characteristics listed in Questions 17 and 18 as a result of increased wheeling. As for what models and engineering expertise are required, we are not aware of any existing or proposed models that are capable of such estimates. Because the reliability and economic impacts on any one system due to increased wheeling would be different than that for another system and because the impacts on each system would be extremely sensitive to system specific parameters and the amounts of increased wheeling considered, there are no simple or straight forward answers to this multipart question.

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Not at the present time.

Reliability - No, not accurately. However, using load flow and transient stability programs, a reasonable value may be obtained. Economics - No, not accurately. However, using unit commitment and production costing programs, a reasonable value may be obtained.

Models are Unit Commitment, Promod III, Proscreen II, and TIGER for generation, while load flow and transient stability programs developed by Power Technologies, Inc. are required for transmission.

Expertise required includes knowledge of the above models, experience in utility operations, reserve policy, reliability obligation, probability assessment and risk assessment.

"Standard" planning and operation computer models could make valid estimates of the economic impacts. Reliability assessment may be more judgmental.

Determination of the detrimental effect on reliability would be difficult to calculate. If that can be determined, the economic impact of maintaining a level of reliability can be calculated.

Same answer as the response to Question 20 except that increased wheeling will cause additional complications that will increase analysis requirements.

No, we cannot accurately quantify in advance the reliability and economic impact of having less centralized control of non-utility generation as a result of increased wheeling, and we are not aware of any model that can accurately do so.

No. This would require substantial efforts using both existing power flow and stability analysis and the development of better techniques for determining system reliability. It would also require increased sophistication in on-line system control facilities to manage the multitude of small schedules, and better ability to estimate the economics which may occur in various regions for generation. It would be expected that installed generation reserve requirements would increase unless all IPP's and QF's had to adhere to rigid area power reliability standards.

27. No. Economic impact can be assessed, but only to a limited degree. An after-the-fact analysis would have to be performed, estimating what generating units would have been operating at the time. The use of a production costing model would be required; best results would be obtained with a deterministic production model, as opposed to a probabalistic model.

Reliability impacts would be very difficult to assess. Reliability studies on the system are performed using actual unit histories on existing units. The entire analysis depends in turn on the assumptions used. Increased wheeling may introduce more NUGs to the system, and unless there is an incentive to properly maintain NUG facilities, the reliability will suffer. cannot accurately calculate the impact this may have at this time, since we have very little experience with NUGs.

No.

QUESITON 28

PLEASE COMPARE (AS QUANTITATIVELY AS POSSIBLE) ALL FIVE SCENARIOS FOR THEIR IMPACT ON COST, RELIABILITY, AND QUALITY OF SERVICE.

At this time, the has not performed any quantitative studies or analyses of the five scenarios to determine their impact on cost, reliability or quality of service. The five scenarios presented range from maintaining the existing way of doing business, with minor modifications to the regulatory process, to a totally disaggregated, market-based system.

In general, some of the technical problems and needs we observe as one moves from Scenario 1 to Scenario 5 are:

- Lead times for licensing, design and construction of new transmission become an important planning priority, particularly if "enough" transmission to accommodate nondiscriminatory access and wheeling is "required."

- The problem of fair compensation for "required" transmission use and construction due to increased or mandatory access would need to be addressed.

- The idea of optimal economic dispatch will gradually disappear as one moves toward Scenario 5, as supply is generated by contractual arrangement and excess transmission capacity dries up.

- The "contractual" versus "electrical" path portends the need for evolutionary, strict system controls to prevent "inadvertent" wheeling.

- Effective planning will require early disclosure of proposals by third parties and possible utility intervention in sizing, design and site location.

- Effective operations will require coordination of maintenance, standardization with respect to frequency and voltage regulation and system protection.

- The cumulative environmental effects of numerous small generators must be addressed.

- Fuel use policies become more significant.

The difference in cost, reliability and quality of service between the five scenarios and how much change from the existing way of doing business could be implemented without increasing customer costs, reducing reliability or reducing quality of service are complicated questions which will require substantial analysis and industry input before such changes should be made.

The supports the concepts of increased competition and increased transmission access and wheeling with fair pricing mechanisms as a means of providing the lowest cost electricity to the consumers in a manner which will not degrade the quality of service or the reliability and coordinated operation of the bulk power electric system.

SCENARIO IMPACT ON

Scenario	Cost	Reliability	Quality of Service
1	+	Same	+
2	-	-	-
3	-	--	--
4	-	--	---
5	--	--	----

\+ Relative Degree of Improvement
\- Relative Degree of Degradation

Scenario 1 may enable utilities to lower costs because of favorable reaction by the financial community. Rolling prudence reviews could improve quality of service by involving the regulators in the utility's resource planning process. More efficient calculation of avoided cost and subsequent decrease in ratepayers costs to QF's should lower the price of electricity to ratepayers.

In Scenario 2 the reliability and quality of service may detiorate due to the inequities and inefficiencies in responding to the demands of compliance by contract. Dispatching QF's and IPP's generation according to contract terms could be difficult to coordinate. Costs could increase due to utilities backing down baseload generation in order to accommodate cogeneration during minimum load periods.

The conditions outlined in Scenario 3 could lead to a degradation of the quality of service because level of service will be dictated by power supply prices. Increased pressure for transmission access by all power suppliers will also contribute to a degradation of service.

The system operation of the nation's electrical system will be specified in contracts in Scenario 4. These contracts will not convey the requirement of "duty to serve" which currently exists in the utility industry. Reliability and quality of service will degrade proportionately to the number of contracts that are needed to supply electricity to all customers.

Scenario 5 could be the most detrimental to the nation's utility industry when compared to the previous 4 scenarios. The division of the utility industry into separate generation, transmission, and retail distribution segments could produce cost inefficiencies and a degradation of both reliability and quality of service. To plan for future generation and transmission entails intense coordination of all parties involved. The desired level of competition that this scenario projects will only lead to less coordination among entities and thus a corresponding loss in the quality of service to the nation's electrical customers.

28. Scenario 1 continues current industry structure and procedures; current regulatory jurisdiction but with modifications to avoided cost pricing rules under PURPA, and voluntary wheeling. Under this scenario, is currently providing highly reliable service at the lowest possible cost. Therefore, this scenario will be considered the benchmark for evaluating Scenarios 2 through 5.

Scenario 2 provides for mandatory transmission access for utilities and large retail customers and less restrictive qualifications for QFs. The resulting uncontrollable power flows on the transmission system and their adverse impact on reliability and economic operation would likely require additional transmission facilities. Both would increase operating costs. The likely possibility of large retail customers utilizing mandatory wheeling would result in higher rates for the remaining customers who are unable to benefit from these arrangements. Reliability in future years could be reduced if these large customers discontinue wheeling and the local utility, obligated to serve, has insufficient capacity to meet reliability criteria.

Scenario 3 provides for all-source bidding for new capacity and mandatory wheeling for utilities only. This approach would likely result in greater dependence for additional capacity on resources with no obligation to serve, whose availability and performance is controlled only by contractual commitments and financial penalties (which could be subject to litigation) and which may be located unavoidedly so as to adversely impact economic operation. Mandatory wheeling also would likely result in importation of capacity with the inherent risk of lower availability due to transmission constraints. These risks to reliability could be reduced by the installation or purchase of additional reserve capacity. This approach also may favor capacity additions for short term savings while sacrificing the long-term benefits of alternatives, with the result of increased costs in future years. In summary, increased dependence on IPPs and wheeling would tend to reduce reliability and increase costs and the impact on each is interrelated.

Scenario 4 and 5 entail restructuring by segregating a competitive generation sector from transmission and distribution sectors with essentially all of the features of Scenario 3. The above analysis of Scenario 3 applies to both 4 and 5, and unless the issues listed in response to question 22 are resolved satisfactorily, reliability would decrease and operating costs would increase due to reduced coordination of power supply resources. The segregation of utility sectors and the resultant overlapping regulatory oversight would most likely delay needed reinforcements. Reliability would suffer from greater reliance on contractual commitments for power supply from entities having no obligation to serve. It is difficult to conceive that these modifications would not result in higher costs.

28. The Scenarios cover a continuum of circumstances from the present utility structure to a complete restructuring. Somewhere along the way, service to customers would deteriorate and costs would increase. While this point may move as experience with the new structure is gained, reliability responsibilities would tend to shift toward end users and away from distribution, transmission, and generation entities.

A conflict would also arise between the traditional utility obligation to serve and NUGs, which might discontinue generating under temporarily adverse economic circumstances, only to return as those circumstances improved.

28.

Unfortunately, it is not possible to examine a generic description of the future electric industry and develop the thousands of pieces of data required for a truly quantitative analysis of the impact of proposed changes. Experience with PURPA indicates that tampering with a complex system that is working well will invariably result in some degree of chaos and increased cost. Scenario 1 would be the least disruptive and most effective way to address any problems that currently exist.

While the sweeping changes proposed in Scenarios 2-4 could benefit the stockholders of a few troubled and vocal utilities, along with several special interest groups, the effect in the vast majority of service areas would be reduced reliability and increased cost to customers.

Scenario 2, "Expanding Transmission Access in the Existing Institutional Structure", simply enlarges the group of preferred non-utility suppliers that have already cost consumers millions of dollars, and proposes to strap utility customers with investment charges for under-utilized facilities. Scenario 3, "Competition for New Bulk Power Supplies", adds another variety of unregulated entities that will seek to maximize profits at the expense of electric consumers. Scenario 4, "All Source Competition for All Bulk Power Supplies with Generation Segregated from Transmission and Distribution Services", and Scenario 5, "Common Carrier Transmission Services in a Disaggregated, Market- Oriented Electric Power Industry", attempt to replace a carefully engineered and meticulously operated electrical system with an untold number of individual contracts. It is preposterous to think that the current minute-to-minute optimization of electric generation, transmission and distribution can be duplicated, much less improved upon, by a vast set of inherently rigid contractual arrangements between existing utilities and a host of inexperienced and opportunistic power producers. Given only the five scenarios from which to select, Scenario 1 has assisted in development and support of the world's most advanced economy by providing a reliable, low-cost electric supply. The risk of the most certain disruption of this functional electrical system must be carefully weighed against the alleged "gain" based soley upon unproven economic theories.

Question 28

Any quantitative comparison of the five scenarios would require a lengthy study based on numerous underlying assumptions. Such studies have not been made, but some general, qualitative observations can be offered:

SCENARIO I

- o Cost of Service - Because of the greater certainty of utility cost recovery, the utility should be able to provide service at a slightly lower cost than is available today. The greater assurance of cost recovery could be expected to be reflected in lower utility financing requirements, which would make utility investments more attractive, all of which convert to lower cost to the customer.

- o Reliability of Service - The greater assurance of cost recovery for capital expenditures for generation, transmission and distribution improvements should enhance the utility's ability to maintain reliability of service. Since the growth rates forecasted in investment decisions would already have regulatory approval as a result of the rolling prudence revisions, it would be easier to attract capital and the timing of future utility facility improvements and construction programs would be less subject to cash-flow-related constraints.

- o Quality of Service - The ability to more easily attract capital should enhance the utility's ability to maintain quality of service, should Scenario 1 be adopted.

SCENARIO 2

- o Cost of Service - Scenario 2, since it would tend to increase the complexity of utility operations and permit limited mandated transmission access without any strengthening in the existing regulatory-utility bargain, would tend to weaken the overall financial position of utilities. It is not evident from Scenario 2 that transmission service pricing would be sufficient to fully support the impact associated with the

(Continued)

loss of utility wholesale and large retail customers with respect to possible stranded generation investments.

- o Reliability of Service - Service reliability would be somewhat poorer than is the case in Scenario I because of: the increase in transmission and generation service complexity; the greater difficulty of securing capital; and possibly reduced revenues resulting from customer migration effects.

- o Quality of Service - Quality of service would probably deteriorate, particularly for smaller commercial, industrial and retail customers. The principal customer migration effects would be anticipated to occur in the large wholesale utility, and large industrial customers who might shift to QF or IPP supply sources.

SCENARIO 3

- o Cost of Service - Cost of service in Scenario 3 cannot be evaluated as the competitive bidding procedures are not precisely defined. It is conceivable that with proper competitive bidding procedures, including full ability of the utility itself to compete both as a regulated and nonregulated generation supplier in meeting its own load, bidding might result in some savings in the generation area. On the other hand, it would appear that reduced investor and/or financial community confidence in the resulting utility structure could result in increased financing costs. Also, if the states were to require that additional transmission facilities be constructed to provide for undefined amounts of in-state wheeling, this might result in significant additional and otherwise unneeded investments in transmission facilities.

- o Reliability of Service - Service reliability in the generation and transmission sectors would probably be somewhat less than is the case today. The reason for this is that not all generation developers would have the objective of providing the most reliable plant. Rather, their objective might be oriented towards short-term economic returns. The control, dispatch and operation of the generation would be more complex

(Continued)

and less reliable than is the case with the current integrated system. Also, the transmission system configuration and loadings might be less optimized than is the case with Scenarios 1 and 2.

- o Quality of Service - Quality of service would probably decline for all categories of service. The reason for this is that in Scenario 1, and to a lesser extent in Scenario 2, the integrated system has certain economies which permit a higher quality of service provision for a given revenue stream. It is very possible that transmission pricing of Scenario 3 would have to be increased to reflect the greater reliance on transmission service and additional facilities which might be required.

SCENARIO 4

- o Cost of Service - The separation of the generation segment could result in a severe impact to the financial structure of existing utilities. From a financing standpoint, it is possible that a significant percentage of the bonded indebtedness would have to be paid off and a new bonded debt issued at a higher rate of return. There would appear to be significantly less dispersion of overall risks and assurance of return in the non-integrated entities remaining. This could increase financing costs and result in increasing costs of overall utility service. It is particularly difficult to envision how the financing and operation of the "transmission only company" would be handled from the structural viewpoint. The additional complexities at the generation and possibly the distribution levels would inevitably reduce the reliability of service.

- o Quality of Service - Quality of service would almost inevitably deteriorate because the final responsibility for quality of service would reside with the distribution company which has little control over the generation and/or transmission company. In addition, the distribution company would have a significant incentive to secure service from the lowest cost generation supplier -- even though this might involve using two or three transmission companies, in which case it could be difficult

(Continued)

to tie down responsibility for service outages or interruptions.

SCENARIO 5

- Cost of Service - The complete segregation of the integrated industry structure would inevitably result in significant cost increases if the same level of service reliability and quality could be maintained, which is questionable. The cost of transmission operations would inevitably rise significantly because the transmission company would, in some way, have to provide for operating contingencies, voltage regulation, spinning reserve, and other functions currently performed by the integrated system. It is to be questioned if the common carrier system could be capable of providing some of these functions, and if so, how would they finance such functions. The transmission companies would, under the common carrier systems, be operating as a tightly regulated supplier of service, who has little incentive to provide the highest quality of service. Also, the regulated transmission company would have a greater incentive to "cream skim" the high load factor customers from the distribution company.

- Quality of Service - The only customers who could anticipate receiving a high quality of service from the transmission company are the very large high load factor industrial customers and very large distribution utility customers. The reason that these customers could elicit a high quality of service is that they always have the alternative of turning to self generation for a major part of their supply and could continue to demand standby and maintenance as well as quality service from the transmission company.

	Scenario				
	1	2	3	4	5
Cost	Some Less	Greater	Same or Less	Same or Less	Greater
Reliability	Same	Same or Less	Same or Less	Same or Less	Less
Quality of Service	Same	Same or Less	Same or Less	Same or Less	Less

The effects discussed above are relative to the present day operating, planning and regulatory environment. It is important to recognize that there are many operational uncertainties that could affect how well the system described in each scenario would work in practice. Because of these uncertainties, the effects on cost are particularly difficult to assess.

The economic benefits realized through increased competition in the generation sector will be offset in all cases by increased transmission costs. Our attempts to assess which effect would dominate are based on very qualitative judgment. It is our belief that reliability and quality of service would at best, remain the same as present, but this is also based on mostly qualitative considerations.

The utilities in the north-central U S encompassed by the [redacted] have developed a very workably efficient and reliable electric system which has allowed many entities to participate (IOU's, REA's, municipals and the Federal government) and obtain the benefits of interconnected operation. This system and its planning and operating guidelines, procedures and cooperation has been developed over many years and allows those that participate significant flexibility in making transactions to improve the economic efficiency of the system while still maintaining its integrity. Given this environment and experience, we do not see a compelling urgency to effect any dramatic changes. We believe any changes should be well thought and made incrementally to allow those planning and operating the complex electrical networks an opportunity to assess the real impacts and costs associated with the changes.

28. All scenarios, other than Scenario I, are based on one or more of the following assumptions:

- Future capacity of the appropriate type can be provided more cheaply by NUGs independent of utility control.
- Transmission capacity is or will be virtually unlimited.
- Current levels of reliability will be technically feasible in the environments postulated.
- Utilities will have information, financial capability and incentive to guarantee such reliability.

None of these assumptions is valid.

Pressure to change the electric utility industry is based on the misrepresentation or misunderstanding of the nature of the current industry condition. It is driven by abstract concepts of the inherent good of competition and by the desire for short-term financial benefit.

The problems the industry is experiencing are not problems resulting from current circumstances, but are the lingering consequences of past circumstances. These problems include surplus capacity and cost impacts, including regulation-imposed costs, as the result of large, long lead-time capacity additions. The proposals for change do not address, and will not solve, these problems. These problems can only be resolved by utilities, at the likely expense of their investors in the long-term and customers in the near-term (except in those instances where government intervenes and transfers costs to the taxpayer). The solutions include cost cutting, creative financing, incentive rates, external power purchases, mergers and even bankruptcy.

Looking forward, the utilities have numerous options to construct or purchase capacity and superior expertise to meet future supply needs. Only the utilities have the obligation to assure a reliable supply. "Deregulation" in response to self-serving pressures for short-term gain will come initially at the expense of utilities' captive customers, and ultimately at the expense of a reliable national power supply. Change to encourage competition, as defined by its advocates, will have the same results.

The impacts of electric supply on the national economy and security are unique. A telephone call which does not go through can be placed again. An airliner can leave late or arrive late. Natural gas can be stored and delivered at a time different from its production or replaced by a substitute fuel. Electricity, which is produced and consumed in the same instant is not as flexible and miscalculations can be very unforgiving.

The consequences can be measured in terms far more severe than various levels of inconvenience. The process of electric power supply is extremely complex. Government-mandated changes should only be made after careful, knowledgeable and pragmatic analyses of the long-term and short-term impacts of these changes. Only in this way is there any assurance that benefits will exceed risks.

We are unable to quantitatively evaluate these scenarios as to their impact on our system. However, we feel, as shown by the deregulation of other industries, that only a few select customers will benefit from such activities. For the vast majority of citizens, those who are unable to "shop around" for their power, service will only become less reliable, more frustrating, and more costly! We have one of the best electrical systems in the world; we should not jeopardize it by implementing new regulations and procedures in a hurried fashion. If changes are necessary, they should be examined thoroughly by all parties involved and then implemented slowly in a manner that is best for the vast majority of citizens.

The five scenarios describe increasingly uncertain futures such that a quantification of their outcomes on reliability and quality of service is almost impossible. On the basis of uncertainty, scenarios two and three might be interchanged due to the concept of retail wheeling.

Retail wheeling is seen as increasing uncertainty in the area of utility planning in that the lead time for industrial development has historically been less than the lead time for utilities to plan for, gain regulatory approval and install generating facilities. With retail wheeling, it is questionable if there would be sufficient speculative construction to meet future requirements.

The transmission grid as it exists today is a result of utilities jointly planning an efficient system to maximize reliability and share reserve capacity. It was not designed for point-to-point distribution of power. The scenarios requiring mandatory wheeling would likely reduce this cooperative relationship, which has existed in past years, and lead to reduced reliability.

In the electric utility industry, contract paths and actual flows are seldom the same. In the scenarios that require mandatory wheeling, it is uncertain what actions utilities would take if their lines become burdened by noncontract flows.

Scenario 1

This is basically the status quo, except that it relies on "state regulated curtailment policies." The ability to curtail generating unit output and/or customer load in a timely manner is absolutely essential to maintaining system reliability. System emergencies come in an infinite variety. The discretion to select and to implement a curtailment in the heat of battle in a specific emergency must reside with utility system operators. The concept of "state regulated curtailment policies" is not meaningful. Likewise, the notion that "for outages of non-utility wheeled power, curtailment and backup power are based on standby service contract with local utility "is also not meaningful. Decisions to curtail generator output, wheeling, and, in the extreme, customer load are of necessity made under fire by responsible individuals whose training and experience make them uniquely qualified and must be tailored to the specific circumstances of the emergency. The public safety and welfare cannot be subordinated to special interest groups.

Scenario 2

1. The concept of States requiring utilities to "include provisions for adequate transmission capacity for wheeling services in system planning" is not meaningful. Absent a contract for a wheeling service which is specific as to source, destination, magnitude, duration, and character of service, the construction of transmission for wheeling would be a speculative investment which the utility would have no way of recovering.

2. Since transmission systems are fully utilized at present to effect maximum economies on behalf of all customers of the owning utilities, the establishment of provisions for mandatory wheeling for special interest groups will impair reliability and/or economy of service to customers of the owning utilities, either of which outcomes would be adverse to the public interest.

3. Again, the concepts of "state regulated curtailment policies" and emergency curtailment of non-utility wheeled power based on contracts are not meaningful.

Scenario 3

1. Transmission access as a precondition for utility participation in competitive bidding would have a chilling effect on utility participation which would in many cases have the practical effect of precluding utility involvement. Given the near impossibility of building substitute transmission, utilities would be unable to make their limited transmission available unless relieved of the obligation to serve.

2. Any type of mandatory transmission access will be adverse to the public interest as it will subvert the societal objectives of reliability and economy of service.

(Continued)

3. The concept of States requiring utilities to plan adequate capacity for instate wheeling and for regional transmission needs will result in speculative construction and increased cost to customers.

4. If the gradual transformation of the generation sector to an all competitive system as existing capacity is retired is realized, cost to society will increase as such generators will no longer be dispatched on a regional uniform cost-signal basis. Reliability will be impaired as the competitive generators will not be subject to the absolute control of a central authority during system emergencies.

5. The conversion to an all competitive system will call into question the very concept of a power pool, the essence of which is coordination, cooperation, information sharing, including costs of production, active assistance, etc.

Scenario 4

1. This scenario is confusing. It first describes an industry structure consisting of competitive generation companies and combined transmission/distribution companies. It later describes an electric industry structure which is similar to the natural gas industry, i.e. producers, transmitters and local distributors.

2. The concept of the transmission entity being able to maintain system reliability and coordination amidst a myriad of independent, uncoordinated, totally competitive generation entities is academic at best and flies in the face of real world operating experience.

3. The concept of mixed federal-state regulation of transmission capacity and services is absurd.

4. Utilities already consider and coordinate regional transmission needs in the planning process and have done so for many years.

5. The concept of imposing upon utilities the additional obligation to provide transmission capacity for instate wheeling is ludicrous in light of documented cases of utilities being prevented from constructing transmission lines urgently needed to supply their own customers.

Scenario 5

1. The circumstances described in this scenario are antithetical to the concept of the power pooling and its attendant benefits of reliability and economy of service to all customers.

2. This scenario is highly unrealistic as the concept of an alternating current electric power transmission network functioning as a common carrier is fundamentally flawed for the following reasons.

   a. Unlike the cargo transported by classic common carriers such as a railroad, intercity bus company, or trucking company, electricity must be delivered at the very instant it is produced.

(Continued)

b. Unlike the goods transported by classic common carriers, electricity cannot be directed to flow between source and destination via specific transmission circuits owned by specific utilities.

c. Unlike the transportation capacity of a classic common carrier, the transmission capacity of an electrical network varies unpredictably and widely from day-to-day.

d. Unlike a classic common carrier, the transmission capacity of which can be supplemented in the near term to accommodate increased traffic, e.g. by acquiring more locomotives, more cars, larger cars, etc., the capacity of an electrical transmission network cannot be supplemented in the near term to accommodate fluctuating demand for transmission service. The implementation of transmission reinforcements represents a long, costly and unpopular undertaking, the eventual outcome of which in today's societal, regulatory and legal milieu is highly uncertain.

A quantitative comparison is not possible at this time. In general, with increasing scenario number we would expect higher customer costs, less reliability, and decreasing quality of service. A look at what has occurred in the telephone industry is an appropriate comparison.

These scenarios present significant issues dealing with independent power producers. These issues include long-term power supply uncertainty, reactive support, siting considerations as well as control and regulation problems. It is not possible to quantitatively compare these scenarios but the severity of the problems increase dramatically in moving from Scenarios 1 to Scenario 5.

SCENARIO 1 - Strengthening the existing regulatory-utility bargain.

SITUATION: Mostly status quo with minor modifications in rules regarding avoided cost calculations and rate of return measures for utilities. Transmission access would remain voluntary and under the control of each control area.

TECHNICAL PROBLEMS:

These issues deal primarily with independent power producers or non-utility generation (NUG).

(1) Supply Planning Uncertainty - Can a utility or region of the country depend on the long-term availability (fuel supply is primarily oil/gas), future economic viability, and enforceability of long-term NUG supply contracts?

(2) Reactive Power Support and Voltage Control - Most NUGs provide significantly less reactive support to the transmission network than the utility generation they displace. They can, therefore, produce voltage problems if not dispatched in combination with the utility's own generation.

(3) Siting Considerations - Without proper planning and coordination, the siting of NUGs can present significant reliability problems. A concentration of NUGs in one area may create transmission loading problems, reduce stability margins, and increase short circuit levels beyond the interrupting capability of existing equipment. The lack of dispatchability can create intolerable system reliablity problems in cases where adequate transmission does not exist to support a concentration of NUG capacity.

(4) Control/Regulation - Large concentrations of NUG capacity in one control area can significantly impact the ability of that utility to match load and generation on a continuous basis in accordance with NERC operating guides as uncontrollable NUG capacity displaces utility-owned generation that is used for regulation.

(Continued)

(5) Construction Lead Time for New Facilities - Due to the short lead times for NUG capacity and improper planning/coordination with utilities, transmission is often not available to fully support the combination of NUG and utility-owned capacity in certain areas of the network.

(6) Backup Capacity Requirements - PURPA requires utilities to provide standby capacity to qualifying facilities. Potential oil/gas curtailments could have a serious impact to regions heavily dependent on NUG capacity.

(7) Dispatchability - NUG energy can be sold to the connecting utility or other utilities or used to serve its own local load. Changes from one of these modes to another can occur on an hour-to-hour basis. This can cause system dispatching problems/complications and adversely impact reliability. NUG's operated base loaded during off-peak hours can force the shutdown of utility generation because of minimum load constraints. In some cases, these units may not be able to be restarted the next day because of thermal constraints.

TECHNOLOGIES REQUIRED FOR IMPLEMENTATION

None

SCENARIO 2 - Expanding transmission access in the existing institutional structure.

SITUATION: PURPA legislative changes increase the number of buyers/sellers. Utilities and large industrials become eligible to apply for mandatory wheeling. Policies intended to encourage bulk power sales and wheeling will be expanded.

TECHNICAL PROBLEMS:

(1) Problems identified in Scenario 1 are increased.

(2) Parallel Flows - Even though contract path provisions are maintained, control areas will encounter difficulty in mitigating first contingency loading problems because of the number of multiparty transactions.

It will be very difficult to identify which transactions need to be curtailed to mitigate problems.

(Continued)

(3) Transmission Planning - Because of uncertainty in NUG locations and mandatory wheeling transactions, very little planning for new facilities could be made. Since utilities would not have control of their own transmission facilities for the benefit of their ratepayers, new transmission would probably not be planned.

TECHNOLOGIES REQUIRED FOR IMPLEMENTATION

Online security monitoring systems involving regional evaluation.

SCENARIO 3 - All source competition for new bulk power supplies with market based pricing. Transmission access is expanded to ensure that new power suppliers have utility participation in the competitive bidding system and that mandatory wheeling orders are available from FERC for utilities. Transmission prices are regulated by NERC.

(1) Problems identified in (1) and (2) are expanded.

(2) Competition - Coordination between utilities would tend to be reduced in both the planning and operating environments.

(3) Heavy Transmission Utilization - Transactions will tend to be made involving large energy transfers across many systems and at great distances without proper consideration for reliability. Typical problems will include:

(a) Dynamic instability
(b) Inability to dispatch generation on economical basis
(c) Voltage collapse
(d) Thermal overloads

TECHNOLOGIES REQUIRED FOR IMPLEMENTATION

(1) Online security monitoring systems involving regional evaluation.

(2) Because of planning uncertainty, it will be difficult to identify what technologies (facilities) are needed.

(Continued)

SCENARIO 4 - Vertical segregation/all source competition for all bulk power supplies with generation segregated from transmission and distribution services.

SITUATION: Segregated utility generators, QFs, and IPPs compete to provide supply to transmission distribution and local distribution companies. Some transmission companies act as power brokers.

TECHNICAL PROBLEMS:

(1) Capacity Planning - Transmission companies could plan for new generation within their system, in another system, an NUG in another system, etc. It would be extremely complex to coordinate transmission planning on a regional basis. For example, how could each system model where the generation is going to come from for any particular year?

(2) Reactive Power Supply - Problems identified in previous cases would be further aggravated because of long-distance energy purchases. Transmission companies with high-cost local generation would not have sufficient online reactive supply to provide adequate system reliability.

TECHNOLOGIES REQUIRED FOR IMPLEMENTATION

(1) Same as for Scenario 3

(2) Integration between EMS Systems

SCENARIO 5 - Common carrier transmission services in a vertically segregated industry.

SITUATION: The industry is segregated into separate generation, transmission, and retail distribution segments. Regulated transmission systems are operated as common carriers. Regulated local distribution companies provide retail services.

TECHNICAL PROBLEMS:

(1) Open Access - Chaotic conditions would exist in both the planning and operating environment. System reliability could not be maintained without total integration of EMS systems.

(Continued)

(2) Transmission Additions - Individual transmission companies could not plan for new facilities because of uncertainties in use of the network. They would also be reluctant to build because of uncertainity in the allocation of benefits.

TECHNOLOGIES REQUIRED FOR IMPLEMENTATION

(1) Same as for Scenario 4

Scenarios 3, 4, and 5 allow for competition in a free market for power supply, while at the same time regulating transmission. Obligating "transmission" companies to provide transmission for regional purposes without granting the commensurate authority to build transmission without restrictions or price controls does not seem consistent.

We have similar questions on scenarios 1 and 2 concerning future transmission. It should be recognized that delivering electric service requires both generation and transmission. Occasionally, generation is located at the load site and transmission does not play a large role. When generation is located remote from the load it is to serve, transmission and generation should be considered as a single system. If they must be considered separately, then obligation, regulations, and competition should be similar for both the transmission and generation agents.

INTRODUCTION

The scenarios attached to this questionnaire are written to follow the rule changes as proposed in the FERC NOPRs of March 16, 1988. For this reason, the introductory comments given in answer to this question will address the five scenarios in keeping with the comments on the NOPRs themselves.

believes that if the rules as proposed by the FERC in the IPP and Bidding NOPRs go forward to any significant degree, then action to restructure the electric industry will be set in motion, and will eventually and inevitability lead to the reorganization of the vertically integrated electric utility industry as it exists.

SCENARIO NO. 1

As described in Scenario No. 1, PURPA reform should be undertaken. In the jurisdictions in which operates, the implementation of PURPA has been accomplished through an orderly regulatory process which has resulted in rules and procedures which stand to benefit ratepayers and utilities, and to encourage prudent QF development. This is not the case in all areas of the country.

(Continued)

The FERC rules implementing PURPA were written without prior knowledge of what the response to those rules would eventually be. For this reason, the FERC, after allowing ample time for the rules to operate, held regional hearings in 1987 to establish a record on which to base any needed adjustments to the rules dealing with PURPA.

With but a few exceptions the NOPR resulting from the regional hearings if adopted, would produce change in a positive direction, and would clarify many areas of the now existing rule which are causing confusion.

The remainder of Scenario No. 1 represents very little change from the status quo, apart from the PURPA reform, no significant impacts to our operation would be apparent. The situation for the remaining four scenarios is quite different.

SCENARIOS 2 THROUGH 5

can not quantitatively evaluate the tremendous changes that would occur in the existing utility structure and the resulting impacts on cost, reliability, and quality of service that are described in the remaining four alternative scenarios. The preparation of accurate and reliable quantitative responses would require the resolution of many questions and uncertainties underlying each scenario and substantial study of the potential ramifications of each scenario. There is so much uncertainty embodied in each scenario that our responses can only deal in generalities predicated upon our interpretation of the ultimate direction each successive scenario would move the industry.

Each successive scenario is a result of further implementation of the rule changes as proposed by the FERC. believes that in reality, if the FERC is only marginally successful in implementing its proposed regulatory relaxation for IPPs and its proposed rules for bidding programs, then the restructuring of the electric industry is quite likely. This would eventually lead to a situation resembling Scenario No. 5.

(Continued)

does not agree with the FERC that the proposed rules will encourage additional economies and efficiencies. To the contrary, believes that adoption of the proposed rules will serve to discourage the economies and efficiencies espoused by the FERC, and will further serve to destroy certain existing benefits which have been encouraged and strengthened by the present rules.

28. We are not capable, at this time, to quantatively compare the Scenarios other than by ranking them with respect to one another. We believe the order in which they are currently numbered (1-5) ranks the sceneарios from least to greatest cost, from greatest to poorest reliability, and from highest to lovest quality of service.

The last three of the five Scenarios permit all source competition in an environment somewhat similar to that which the Federal Energy Regulatory Commission (FERC) has recently proposed in three Notice of Proposed Rulemakings (NOPRs). As we stated in a joint response with 39 other utilities concerning two of the the FERC NOPRs (a copy is enclosed), we believe that the Independent Power Producer (IPP) would have significant price advantages over the regulated utility. Unfortunately, these advantages are not of a nature which would benefit consumers, since they consist principally of means by which IPPs can shift costs to purchasing utilities and their customers. These are discussed beginning on page 21 of the enclosed response to the FERC NOPRs.

We also believe that Scenarios 3 through 5 would not only fail to produce the economies that the FERC and others assume they will achieve with their implementation, but instead would result in certain serious diseconomies and inefficiencies, as well as threaten the long-run reliability of electric service, to the harm of the consumer of electricity. It is our belief that a bidding program could not produce workable competition, that Scenarios 3 through 5 would lead to a loss of economies of scale at the generation level, that the vertical disintegration of the utility industry as set forth in Scenarios 4 and 5 would threaten the reliability of electric service and lead to a loss of economies now achieved with the vertically integrated utility, and that Scenarios 2 through 5 would lead to a loss of economies and reliability benefits now being achieved by coordinated activities among electric utilities. Our concerns are set forth beginning at the bottom of page 59 of the enclosed response to the FERC NOPRs.

It is impossible, in our view, to compare the five scenarios on a quantitative basis with respect to cost, reliability and quality of service. We do not have the necessary experience under the various assumptions to do so. As the extent of industry restructuring is increased, however, the uncertainty of effect on reliability and cost is increased. There may also be some shifting of cost burden from one group of customers to another depending on the extent to which some customers could take advantage of a restructured industry more than others. Such shifts in cost burden occurred, for example with restructuring in the telephone and airline industries.

We believe the electric power industry, as presently structured, has worked quite well throughout its history in providing reliable supplies of electricity to the nation at a reasonable cost. While there may well be room for improvement, there is no urgent need for dramatic restructuring, especially when doing so introduces risks that are impossible to assess accurately. Changes in the industry should be imposed cautiously and gradually, with ample opportunity for debate and review of consequences before additional changes are made.

We are unable to quantitatively compare the five scenarios for their impact on cost, reliability, and quality of service. However, it is our opinion as you travel from Scenario #1 to #5, the following will happen:

Cost will increase

Reliability will decrease

Quality of service will decrease

COMPETITIVE PROCUREMENT OF GENERATING CAPACITY:

SUMMARY OF PROCEDURES IN SELECTED STATES

Prepared for

Office of Technology Assessment
U.S. Congress

December 30, 1988

by

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BOSTON PACIFIC COMPANY, INC.

I. INTRODUCTION AND SUMMARY

INTRODUCTION

The Office of Technology Assessment (OTA) is currently studying the opportunities for and constraints to increased competition in the electricity business. As competition increases, the operating and planning needs of the Nation's electric systems still will have to be satisfied. We still must assure that the right amount of generating capacity is built, and that it comes on-line on time and stays on-line as expected. We still must assure that power is generated when it is needed. In addition, we may want to assure that new power plants are built near load centers or transmission facilities, and that some degree of fuel diversity is achieved.

Since bidding systems are becoming the standard approach to accommodating increased competition in the electricity business, OTA asked Boston Pacific Company to provide examples of actual attempts to reflect operating and planning needs in bidding systems. Bidding systems in six states were analyzed and, where possible, an actual bid solicitation was the basis of the analysis.

Following the summary below, Sections II through VII cover bidding systems in Massachusetts, Maine, California, Virginia, New York, and Colorado. The intent of the state summaries is to provide examples of attempts to reflect operating and planning needs in bidding systems, not to describe each and every detail of these bidding systems.

SUMMARY

Right Amount of Capacity

With respect to the need to assure the right amount of capacity, all of the six bidding systems examined herein embody a resource planning effort. The resource planning effort usually dictates the amount of capacity to be solicited and the avoided cost ceiling prices for the bids, although this is not always the case. In California, the identification of a deferrable resource and the estimation of the cost of that resource is a primary step in the bidding system. In Virginia, Virginia Electric and Power Company (VEPCO) did not include an avoided cost estimate in its solicitation.

In California, the move to bidding seems to have increased the amount of control over capacity additions by private power producers. Originally, California posted an avoided cost price and signed standard contracts for whatever quantity of capacity was offered in response. Now, with bidding, a fixed quantity of capacity will be solicited and the lowest price bidders are chosen to fill that need.

Coming On-Line On Time

With respect to the need to assure that new capacity comes on-line on time, at least three separate approaches are revealed in the analysis.

First, a project fee can be required from successful bidders. That fee is forfeited, at least to some extent, if the project is not completed as promised. The project fees vary from $5/kw in California to $30/kw in VEPCO's solicitation. In some cases, California and New York for example, a list of milestones are set and they must be met to show progress toward project completion.

Second, bidders and their projects may be screened before their bid becomes eligible. In Maine, bidders present information that is said to demonstrate that the project can be built and operated as proposed. In New York, bidders are asked by Orange and Rockland to provide information that shows progress has been made toward project development.

Third, projects that are at a higher level of development may earn higher scores in the bidding system. Massachusetts and Virginia are examples of states that use bid scores in this way.

Staying On-Line

Once a project is built, some would argue that the greatest incentive to stay on-line is the fact that a private power producer only gets paid if energy and capacity are actually delivered. But in addition to this incentive to stay on-line, several states charge liquidated damages if the project does not operate as contracted. Maine, California, and Virginia make private power producers liable for liquidated damages if they do not operate as contracted.

Another way to assure that the project stays on-line is to allow the utility to take over operation in certain cases. VEPCO has the right of first refusal to buy a plant.

For example, the utility could buy a project if a bankrupt developer put its project up for sale.

Operating When Needed

When the need to control operation is discussed, dispatchability is the key word. Both the extent to which dispatchability is required and the type of dispatchability required varies across the six sample bidding systems. VEPCO "encouraged" all bidders to offer full dispatchability based on their bid energy price; projects over 100 MW were asked to operate with Automatic Generation Control. Public Service Company of Colorado also would require many private power producers to operate under Automatic Generation Control. Boston Edison in Massachusetts gave a minor number of bonus points to those bidders offering to risk a penalty if they were not available when requested. In California, bidders can offer to be curtailed up to 1,500 hours per year in return for higher energy prices in other hours.

Fuel Diversity and Location Preference

A preference for certain fuels and/or certain locations is sometimes included in bidding systems. VEPCO stated a clear preference for fuels (like coal) with stable prices, and gave higher scores to projects with such fuels. Massachusetts gave a higher score to waste, wind, hydro, and solar projects. With respect to location, four states gave higher scores to locations near load centers or transmission facilities; Boston Edison in Massachusetts and Orange and Rockland in New York actually specified preferred locations.

II. MASSACHUSETTS

OVERVIEW

Status

Boston Edison's RFP dated January 15, 1987 is the example of the Massachusetts bidding system discussed herein.[1] This is the latest RFP from Boston Edison (a draft for the next solicitation is awaiting regulatory approval) and the most widely-publicized of those conducted in the State.

Boston Edison solicited 200 and received 1,848 MW in bids. Winning bids have been chosen for a total of 340 MW, but none are operational. A recent issue of Electric Utility Week (November 21, 1988, page 19) reported that some of the winning bids were withdrawn because of an inability to secure project sites, and others were suffering financial difficulty.

Approach

The scoring system has a Price Component and a Quality Component. The general approach to reflecting operational and planning needs is through the Quality Component. The Price Component ranks the bids in terms of the level and pattern of the pricing offered. The Quality Component ranks the bids in terms of level of development, fuel type, and a long list of factors such as dispatchability.

One gauge of the significance of operational and planning needs (non-price factors) is to state their value in the numerical ranking scheme in terms of the equivalent price discount. A bidder under Boston Edison's scheme could score an additional number of points in the numerical ranking equivalent to a 25 percent price discount with a perfect score on the Quality Component. For perspective, note that Boston Edison awards the same number of points to a bidder that does not front-load its price bid; that is, the bid price does not exceed the avoided cost price in any year.

In addition to the scoring system, a security deposit is used to encourage a bidder to come on-line and stay on-line as promised. At a minimum, the winning bidders, once their contracts are signed, must make a security deposit of $15 per kw. If the project is cancelled before the planned in-service date, all interest on the deposit is forfeited

and a share of the deposit itself is forfeited. The share of the deposit forfeited is equal to the time elapsed since the contract was signed as a percentage of the time originally expected to be taken between contract signing and the originally planned in-service date.

The entire deposit is forfeited and the project is deemed cancelled if commercial operation is not achieved within two years of the originally planned in-service date.

BOSTON EDISON'S RFP: RANKING FORMULA

The numerical ranking procedure is the heart of the RFP. The winning bids are those with the highest score. With the Boston Edison RFP, a bidder's score has two components, a Price Component and a Quality Component. All bidders start with a score of 1.01 points and the maximum score is 2.5 points.

Price Component

The Price Component also has two parts. The first is the Ratepayer Benefit Score which reflects the price discount a bidder has offered. As noted, no bid can have a present value which exceeds the present value of the Ceiling Prices. For each 10 percent discount that the bidder offers, one tenth of a point (0.1) is added to its numerical score. For example, if the present value of the payments at bid prices are 30 percent lower than the present value at the Ceiling Prices, three tenths of a point (0.3) are added to the score.

The second component is the Ratepayer Risk score which reflects the extent to which bid prices are front-loaded; that is, the extent to which the bid price exceeds the Ceiling Price in the early years of the project. If there is no front-loading, twenty-five hundredths (0.25) of a point are added to the score. Front-loading prevents the bidder from earning these points. One hundredth (0.01) of a point is deducted for each year that cumulative present value of payments at the bid prices exceeds the cumulative present value of payments at the Ceiling Prices. In addition, twenty-five thousandths (0.025) of a point are deducted if the bidder does not provide cash or a cash equivalent to cover the full extent to which cumulative payments at bid prices exceed cumulative payments at Ceiling Prices. Another twenty-five thousandths (0.025) of a point are deducted when a bidder, if there is front-loading, fails to offer cash security to cover part of the overpayments.

All bidders with front-loading must offer the utility a second lien on the facility and the book value of that lien must cover the overpayments.

Quality Component

The Quality Component has three parts. First, up to one tenth of a point (0.1) can be added to the score if the bid facility is already commercially available; six lower stages of development, demonstrated by evidence in nine categories, would result in a lower score.

Second, another five hundredths of a point (0.05) are awarded if the "fuel" is waste, wind, solar, or hydro. Third, up to one tenth of a point (0.1) is added to the score if the bidder provides a long list of attributes such as: makes the facility dispatchable by NEPOOL; agrees to have maintenance scheduled by the utility; and provides security payment of $22.50 per kw instead of the minimum of $15 per kw. (Note that dispatchability does not mean economic dispatch at the bid price. Rather, it means that the qualifying facility (QF) may be penalized for not being available to the extent offered in the bid. The bonus points given to a bidder offering this type of dispatchability is the equivalent of a 1.3 percent price discount.)

III. MAINE

OVERVIEW

Status

Central Maine Power's (CMP's) RFPs are the basis for the discussion of Maine's competitive bidding process. The solicitations are those dated September 1984[2] and June 1987,[3] which are referred to herein as the original RFP and the new RFP, respectively.

Established in 1984, Maine's bidding system is the oldest among the current systems in the U.S. Four RFPs had been issued by the end of 1987 and 28 contracts had been signed for a total of 500 MW. Operational projects totaled 275 MW, and another 222 MW were expected on-line by 1991. In its June 1987 solicitation, CMP solicited 100 MW and received 1,444 MW in actual bids.[4]

Approach

Maine's bidding system reflects operational and planning needs (non-price factors) in three distinct ways.

First, bids are screened or pre-qualified. Bidders must demonstrate their ability to build and to operate the facility they propose. The screening requires that the bidder present evidence to CMP that the project is well along in areas such as engineering design and permitting. This is referred to as Capability Demonstration.

Second, non-price factors are included in the numerical ranking of bids. The ranking is referred to as Establishing Negotiation Priority. One rough way to show the relative value of these non-price factors is to state them in terms of equivalent price discount. In the original RFP, CMP made available a score equivalent to a 10 percent price discount for a bidder that did not levelize or front-load prices (i.e., the bid price did not exceed the avoided cost price in any year). For all non-price factors, a bidder could score a number of points equal to that given for a 50 percent price discount. In the new RFP, a 20 percent price discount equivalent is given to a bidder without levelized or front-loaded prices. The additional price discount equivalent for all non-price factors is 40 percent.

Third, QFs are subject to penalties if they do not perform as contracted. The payments for "Liquidated

Damages" are an attempt to make the QF responsible for the cost of replacement energy and capacity if that QF falls short on providing capacity and energy as planned, or if the contract is terminated.

CENTRAL MAINE POWER's RFP

Capability Demonstration

CMP asks that respondents demonstrate their ability to construct and operate the proposed facility. This amounts to a screening or pre-qualification process. The data requirements are substantial; seven pages are used to list the information requirements for the screening. The information would be readily available to a developer that is ready to construct the facility. In other words, acceptable bids will reflect a considerable investment of time and money in actions such as engineering design, fuel contracting, and permitting.

The information requirements are essentially the same in both the original and the new RFPs. Four aspects of the project are included:

1. Project Feasibility as evidenced by items such as engineering and feasibility studies and indications that the project has or will get the necessary licenses and permits;

2. Availability of Fuel Supply as evidenced by items such as fuel supply contracts and hydrological studies;

3. Financial Capability as evidenced by items such as letters of commitment from financial institutions; and

4. Construction and Operating Capability as evidenced by items such as the qualifications of the project manager and the architect-engineer.

In addition, a QF cannot qualify for firm energy and capacity payments unless it meets the test for firm capacity defined by the New England Power Pool (NEPOOL) and agrees to NEPOOL audit provisions. Also, thermal QFs must guarantee an 80 percent capacity factor in CMP's peak periods. The original RFP required that only one of these conditions be met, but now both are required for thermal QFs.

In the original RFP, any QF requesting levelized payments had to offer to establish protection (an escrow account, insurance, etc.) covering the extent to which

payments exceeded avoided costs in the early years of the contract. This protection is now reflected in the numerical ranking.

Finally, the new RFP adds to the pre-qualification criteria the requirement that all QFs commit to a minimum annual generation.

Establishing Negotiation Priority: Original RFP

Each respondent to the RFP is given a numerical score based on four indexes. Each index has a base value of one, so a respondent starts with a score of four.

1. **Capacity Index:** An additional point is added to a QF's score if it meets one of two standards: either the facility qualifies as firm capacity with NEPOOL or it guarantees an 80 percent capacity factor in CMP's peak period.

2. **Endurance Index:** A QF's score is increased by half a point if payments are not levelized -- that is, if the payments never exceed the forecast of avoided cost in any year. Another half point is added to the score if the QF offers a security fund to cover the utility's cost of replacing the QF's energy and capacity if the QF facility does not operate as contracted.

3. **Operating Index:** Increase a QF's score by four tenths of a point if the facility is dispatchable by CMP. Another four tenths of a point can be added if the facility agrees to deliver 55 percent or more of its total annual generation to CMP during the utility's peak period. Finally, an additional two tenths of a point can be added if the QF agrees to allow CMP to schedule maintenance of the facility.

4. **Price Index:** This index reflects the extent to which the QF is willing to take a price below the forecasted avoided cost. For each percent discount offered by the QF, its score is increased by five one hundredths of a point. For example, a 20 percent discount would add a full point to the QF's score through the price index. Note that the Price Index is the only one that has a potential score above two.

Establishing Negotiation Priority: New RFP

The new RFP changes the numerical ranking by adding two indexes to the original four -- the Security Index and the On-line Index. A bidder now starts with one point for each index, or a starting score of six. Also the scores for each index have been changed as follows:

1. **Capacity Index:** An additional point is added to a score if the bidder qualifies as NEPOOL capacity and: if it is a thermal QF, commits to an 80 percent capacity factor during peak periods; or, if it is a hydro QF, agrees to a semi-annual capacity audit and to a minimum generation level. The change from the original RFP for thermal QFs is that both rather than either of these requirements must be met to earn the extra point (as well as to pre-qualify). For hydro, the minimum generation is a new condition.

2. **Endurance Index:** This index essentially is the same as in the original RFP. One change is that the security fund for replacement costs now must be in the form of an irrevocable letter of credit or other cash equivalent. (See the section on liquidated damages to see how much of a security fund must be established.)

3. **Security Index:** This is one of two new indexes. The security index provides protection when a QF requires levelized or front-loaded prices. An additional 1.5 points is earned if no levelization or front-loading is required.

   With levelization or front-loading, the scoring depends on the type of security provided. With 100 percent "liquid" security, 1 point is earned. With 100 percent insurance, 0.5 points are earned. If a first or second mortgage is the security, 0.2 points are earned. A mix of these types of security is allowed and the score would be a weighted average of the point scores noted above.

   A QF with a capacity of less than 100 kw is given a minimum Security Index score of 1 point even with levelized or front-loaded prices. Similarly, a QF with less than 1 MW capacity automatically earns 0.2 points.

   Finally, note that the security covers cumulative overpayments plus interest. Overpayments occur anytime the bid price exceeds the avoided costs forecasted for a year.

4. **Price Index:** The new RFP doubles the points scored for price discounts. Now, each 1 percent price discount earns the bidder 0.1 points; for example, a 20 percent price discount earns 2 points. Discounts from avoided costs are on a present value basis.

   Many different price formulae are allowed and the choice does not affect the score directly. Price bids may be: a constant percent of avoided costs; fixed prices each year; or indexed base rates. Only levelization and front-loading affect the score.

5. **Operating Index:** The new RFP expands the factors reflected in this index. As in the original RFP, dispatchability and the right to schedule maintenance are valued. The value of dispatchability is cut to 0.3 points and scheduled maintenance earns a score of 0.2 points.

   The change is that scores are given for three levels of scheduled operation. A QF that offers to generate only in peak periods earns 1.5 points. (Peak periods occur on weekdays between 8 a.m. and 9 p.m. during April through October, and between 7 a.m. and 9 p.m. during the remainder of the year.) A QF that limits off-peak operation to 25 percent of capacity earns 1 point. A QF that commits to delivering 55 percent of its total annual generation during peak periods earns 0.5 points.

6. **On-line Index:** This is a new index meant to encourage QFs to come on-line later in the 1990's. An additional score of 0.05 points is given for each year the Initial Delivery Date is set beyond 1990.

Liquidated Damages

Liquidated damages are payments made to cover the cost of replacing QF capacity and energy when a QF does not perform as contracted. All QFs are liable for Liquidated Damages as listed below. But the QF decides whether to offer security as described below in order to earn the points offered in the numerical ranking. A standard long-term contract specifies damages in three cases:

1. **Capacity shortfall:** Thermal QFs are liable for liquidated damages if they do not achieve an 80 percent capacity factor in peak periods. After a grace period, the QF's capacity is derated to a level at which the 80 percent can be achieved. Liquidated

damages are paid on the difference between the original committed capacity and the adjusted capacity. The payment per kw of derating is set at three times the NEPOOL Capability Responsibility Adjustment Charge (CRAC). The CRAC is the penalty paid by members of NEPOOL when they do not provide the capacity for which they are responsible.

Hydro facilities also are liable for liquidated damages if they are derated after an audit. The payment is set at three times the CRAC as with thermal facilities, but the calculation is done separately for winter and summer deratings.

2. **Energy Shortfall:** If kwh deliveries fall below the guaranteed minimum, the QF must pay $0.01 per kwh in liquidated damages. A letter of credit or a pledge of securities must be maintained at a level to cover 10 percent of the contingent liability; that is, the security is set up as if the QF will fail to deliver 10 percent of the kwh promised in the upcoming year.

3. **Termination:** Prior to the scheduled initial date of delivery, a QF is liable for liquidated damages if the project is abandoned. The payment would equal the NEPOOL-CRAC times the full capacity of the facility as planned. In addition, a letter of credit must be issued to cover this liability.

   After the initial date of delivery, a QF also is liable for liquidated damages if the project is abandoned. The payment equals three times the NEPOOL CRAC for each kw of the abandoned facility. A letter of credit or a pledge of securities must be issued to cover this contingent liability.

Extension Fee

If a QF fails to meet its scheduled on-line date for any reason, even those covered under force majeure, the contract may be terminated. The contract will not be terminated if the QF pays an extension fee. The extension may be for up to 18 months, and the fee is set at the NEPOOL CRAC.

IV. CALIFORNIA

OVERVIEW

Status

Although California's bidding system has never been used because, since its inception, there has been no need for additional generating capacity in the state, the bidding procedure has been designed in considerable detail. The heart of the bidding procedure is a long-term power purchase contract, referred to in California as the Final Standard Offer Number 4 (SO4). The discussion herein is based on a form of the SO4 contract negotiated by the utilities, private power producers, and commission staff as of June, 1988.

The agreed to SO4 is the contract that will be used when generating capacity is needed and a bid solicitation is announced. However, the investor-owned utilities in the state are now mounting an effort to change the basic bidding regulations underlying SO4.

The current regulations require a price-only bid competition through a second price auction. A price-only competition means that the only variation among the bids is the price discount from avoided cost that is offered. A second price auction means that all winning bidders are paid the same price; that price reflects the discount offered by the first losing bid. The investor-owned utilities propose a change to a competition based on both price and non-price factors. A switch to a first price auction is also proposed.

Approach

There is no numerical ranking in the California system which places explicit value on operational and planning needs (non-price factors). This does not mean, however, that non-price factors are not taken into consideration. California chose to reflect non-price factors through minimum requirements that must be met by all bidders, and financial incentives for additional performance features.

These requirements and incentives are found in five sections of the SO4 contract:

1. Milestones are set to assure that a bidder comes on-line on time, and a $5 per kw project fee is forfeited if the bidder does not;
2. Liquidated damages are assessed if a bidder does not perform as promised;
3. Performance requirements must be met in order to earn capacity payments;
4. Up to 1,500 hours per year of curtailment can be offered; and
5. Additional payments by the utility can be negotiated to gain features such as dispatchability and reactive power support.

FINAL STANDARD OFFER NO. 4

Milestones

If a Milestone is missed, the contract may be terminated and the $5 per kw project fee may be forfeited. The six Milestones are as follows.

1. Submit Quarterly Status Reports: The reports set a schedule for project development and then monitor progress on that schedule. The report asks for evidence that progress is being made on the project.
2. Maintain Site Control: Site Control must be secured and maintained. For example, the QF might show that it owns the site.
3. Complete the Preliminary Method of Service (MOS) Study: An MOS Study is a study of the interconnection costs for the QF. The QF must provide all necessary information for the study, which is prepared by the utility. The QF must pay the utility's cost for the study.
4. Complete the Final MOS Study: Again, the QF must provide the information for and pay the costs of the study.
5. Begin Construction: Construction is defined as continuous work on the installation of major components of the generation project.
6. Establish Reliable Operation: The QF must establish reliable operation by the date set in the contract.

Liquidated Damages

QFs under firm capacity contracts are liable for Liquidated Damages if they default on the contract or if they reduce the level of firm capacity. Liquidated Damages are meant to compensate the utility for losses it incurs because the QF does not deliver capacity and energy as contracted. If the QF defaults on the contract or its firm capacity rating is lowered, the QF must pay an amount equal to the present value of the extra cost to the utility of having to replace the QF's energy and capacity.

Performance Requirements

For firm capacity contracts, the full capacity price is paid on the facility's full capacity only if specific performance requirements are met. The primary requirement is that the facility achieve at least an 80 percent capacity factor during the on-peak times-of-day of each peak month. If the facility fails to meet this requirement, its firm capacity will be derated after a probationary period. If this performance requirement is exceeded, a Bonus may be paid. The Bonus is paid when the facility achieves over an 85 percent capacity factor in each peak month; the Bonus is proportional to the extent to which the average capacity factor in those months exceeds 85 percent.

Curtailment

QFs may agree to have their generation curtailed under certain circumstances. One of two curtailment options must be taken. With the first, a QF could be curtailed only in cases of Negative Avoided Costs and Hydro Spill. Negative Avoided Costs are said to be incurred when the utility's oil and natural gas units are at their lowest level of operation consistent with system needs (minimum load) and the acceptance of further QF deliveries would lead the utility to incur costs higher than costs if QF energy was not accepted. Hydro Spill conditions are conditions under which low system demand forces the utility to allow water to pass an unloaded turbine in order to reduce generation. If either Negative Avoided Cost or Hydro Spill conditions exist, the QF must reduce generation to 30 percent of capacity or less. No energy payments are made during these curtailment periods.

The second curtailment option allows the utility to curtail QF generation up to 1,500 hours per year during off-peak and super-off-peak periods. No more than one

curtailment can be imposed in a single day and the curtailment period cannot be less than three hours. Curtailments can be imposed during periods of Negative Avoided Cost, as described above. Economic curtailments can also be imposed; in these cases, energy payments are based (generally) on actual utility incremental costs. In return for selecting this curtailment option, the QF is paid higher energy prices in some other off-peak and super-off-peak periods.

Adders

An early CPUC Decision ordered the utilities to consider the payment of Adders if additional performance features are requested from QFs beyond those in the SO4.[5] The specific list of Adders is as follows: emergency availability; black start capability; reactive power; scheduled maintenance; real-time pricing; pre-scheduled dispatch; and full dispatchability. Final details have yet to be worked out.

V. VIRGINIA

OVERVIEW

Status

VEPCO solicited 1,750 MW of bids from QFs, IPPs, and other utilities in March 1988.[6] VEPCO received 14,000 MW of bids[7] and chose about 2,000 MW for further negotiation.[8] Final contracts are now being negotiated. VEPCO had solicited bids once before, in December 1986.

Approach

VEPCO's approach to reflecting operating and planning needs in its solicitation involved scores for non-price factors, additional encouragement for offering full dispatchability, performance requirements, and liquidated damages.

In the scoring system, 70 percent weight was given to price and 30 percent to non-price factors. Explicit numerical values were not assigned to specific non-price factors. Rather, the general factors to be taken into account were listed. Project viability was given a 10 percent weight and included factors such as level of development and the experience and financial status of the bidder. Fuel type was given 10 percent weight and VEPCO used those points to express its preference for fuels with stable prices (e.g., coal) and for projects that used in-state fuels. A collection of other factors were given the remaining 10 percent of non-price weight. Included in this group were factors such as location of the project in terms of its proximity to load centers and transmission lines and extent of dispatchability.

VEPCO set the most stringent definition of dispatchability of any solicitation to date. This is the first solicitation to encourage economic dispatch based on energy price. Any project over 100 MW was asked to be dispatched through automatic generation control. The encouragement to offer full dispatchability did not come through the scoring system; dispatchability was one of six items that shared a 10 percent weight given to "other" factors. The encouragement came through other contract terms. For example, non-dispatchable bidders could not ask for indexed energy prices; indexed energy prices lower fuel price risk for the project developers.

VEPCO also reflected operating and planning needs through performance requirements and liquidated damage payments. Performance requirements set limits on the number of days of forced outage and standards by which a bidder's compliance with dispatch orders were measured; capacity payments were to be cut if these performance requirements were not met. Liquidated damages were to be paid if the project did not come on-line and stay on-line as promised.

VEPCO's RFP

Scoring System

- o 70 percent weight to price
- o 30 percent weight to non-price factors:
  - -- Project viability (10 percent)
  - -- Fuel type and fuel diversity (10 percent)
  - -- Other factors (10 percent)

Pricing Structure

- o Both capacity and energy prices will be paid.
- o Capacity prices will be fixed in dollars per kw-year. Limited front loading is preferred (less than 90 percent of total present value in the first 15 years).
- o Energy prices will have two components.
  - -- An O&M component is set for the first year and then indexed for inflation using the GNP deflator.
  - -- A Fuel Compensation Price consists of a heat rate and a fuel price. Although other fuel price indexes are allowed, VEPCO proposes an index for each fuel type.
    - For the coal price index, the Base price is $0.0162 per kwh, VEPCO's average coal cost in the third quarter of 1987. The percentage change in this system coal cost will dictate the changes over time in the prices paid to coal-fired facilities that win the bidding.

- For natural gas, the Base price is $2.018 per MMBtu. The index is a weighted average of residual oil prices, spot market gas prices, and prices of gas to electric utilities.

Dispatchability Requirement

- o All bidders are encouraged to operate under full economic dispatch.

- o In the pro forma contract, dispatch is defined with the following requirements: 6-hour notice for start-up and shut-down, and 5-minute notice for changes in the level of operation. All facilities over 100 MW must be equipped for automatic generation control.

- o The encouragement for dispatchability does not come from bid evaluation; dispatchability is just one of six other factors which, as a group, have 10 percent of the weight in evaluation.

- o Dispatchability is encouraged in other ways. For example, non-dispatchable bidders cannot receive indexed energy prices. (Indexed energy prices lower fuel price risk for the project developer.) Instead, these bidders may receive a fixed price, or an on-peak price equal to VEPCO's average coal cost and an off-peak price equal to VEPCO's lowest cost coal plant.

Performance Requirements

- o A penalty of 4 percent of the capacity payment each year is imposed for each day of forced outage beyond a limit. The limit is the greater of 25 days or 10 percent of the days operated under dispatch. (This is another encouragement to offer full dispatchability.)

- o A penalty of 10 percent of the capacity payment each month is imposed for each time the facility does not operate within 5 percent of the dispatched level of operation; an alternative to this penalty is to declare the incident equivalent to a forced outage day.

Liquidated Damages

- If a facility's dependable capacity proves to be less than expected during the test before commercial operation, the bidder will pay a penalty of $30 per kw of reduction.

- If, during the life of the power plant, dependable capacity is less than 90 percent of what was expected, the bidder pays a penalty of $21.60 per kw of reduction; this penalty is increased each year to keep pace with inflation.

- Each successful bidder pays $30 per kw in Earnest Money. If the facility does not reach commercial operation within two months of the scheduled date, the bidder loses 10 percent of the Earnest Money in each of the next ten months if the project does not come on-line.

- VEPCO has the right of first refusal to buy a plant. For example, the utility could buy a project if a bankrupt developer put its project up for sale.

VI. NEW YORK

OVERVIEW

Status

Orange and Rockland's draft RFP dated October 1, 1988 is used herein to illustrate the bidding system in New York.[9] This is the first time bidding will be used in New York, and Orange and Rockland is one of the first of seven utilities in New York that will solicit bids.

Orange and Rockland will solicit about 100 MW of bids from QFs and IPPs; the amount can be increased at the discretion of Orange and Rockland and may be lowered to the extent they accept Demand Side Management bids received in a concurrent, Demand-Side solicitation. If everything proceeds on schedule, bids will be submitted on July 31, 1989.

Approach

Orange and Rockland reflects operating and planning needs through eligibility requirements and a ranking process. Bids must meet a long list of minimum requirements to be eligible for consideration. Some of those requirements are to provide information such as a milestone schedule, a permitting schedule, a financial plan, and preliminary engineering design. Other requirements demonstrate progress on the project such as a letter of intent with a thermal user, a letter of intent for ownership or lease of the project site, and a letter of interest from fuel suppliers. Finally, one of the major eligibility requirements is a performance requirement that the bidder be available in 80 percent of the peak and shoulder peak hours of the year.

The ranking process has 21 categories gathered into three groups: economic factors with 55 percent of the points; project status and viability factors with 25 percent of the points; and non-economic factors with 20 percent of the points. Fifty of the 55 points available for economic factors are tied to the price discount; each 1.5 percent price discount from avoided cost earns the bid 1 point so an (unlikely) 75 percent discount is needed for the maximum score.

Dispatchability is included as an economic factor and, if offered, a bidder is given four points, the equivalent of

a 6 percent price discount. A moderately strict definition of dispatchability is used. The project is dispatchable up to 300 separate times a year during the system's 4,000 off-peak hours. One hour pre-notification is required for start-up and there is a minimum, two-hour run time.

Project status and viability factors often build on the eligibility requirements described above. For example, a bidder must submit a financial plan to be eligible, but that bidder must show that a 1.5 debt ratio will be achieved in order to earn points for that project's financing plan. Similarly, a letter of intent must be submitted to show site control, but to earn the points for site control the bidder must have moved forward to actual ownership or lease.

Non-economic factors include items such as fuel type and environmental benefits, whose values are difficult to quantify.

ORANGE AND ROCKLAND'S DRAFT RFP

As noted, operational and planning needs are reflected through eligibility requirements and the ranking process. The factors included in the ranking process are summarized here.

Economic Factors

Fifty points are available for price discounts. Each 1.5 percent discount from avoided cost earns 1 point. Four points are given if dispatchability is offered, as described above. If prices are not front-loaded or security for front-loaded prices is in cash, one-half point is earned. Another one-half point is earned if prices are fixed in cents per kwh rather than indexed to market conditions.

Project Status and Viability Factors

One point is earned if the project has QF certification for a technology that has previously been certified. Two points can be earned for each of the following:

- o the project is already constructed;
- o all permits have been obtained;
- o a letter of intent for at least 50 percent of project financing has been signed and the project's expected debt ratio averages 1.5;
- o the bidder has developed a similar project before;

- o the technology has been used in at least 2 currently operating projects;
- o a contract has been signed with the thermal user;
- o wheeling is not required or a letter of intent for wheeling has been signed;
- o a contract has been signed for fuel; and
- o the liquidated damages fund is in cash.

Three points can be earned for each of the following: a detailed engineering design and cost estimate is provided; and, the project site is owned or leased.

Non-Economic Factors

Preference is shown for specific fuel types. Oil earns a score of zero while the score for gas is two points, the score for coal is three points, and the score for waste, hydro, and other renewables is four points. In addition, points for environmental benefits are given by fuel type with fossil fuel cogenerators earning two points, waste and hydro earning four points, and solar and wind earning seven points. Fossil-fired projects that do not cogenerate earn zero points.

Location in narrowly defined load centers earns one point. Thermal efficiency of 65 percent or better earns three points. A contract term of 10 to 14 years earns 2.5 points, while a contract term of 15 to 20 years earns five points.

Project Fee

A project fee of $18 per kw is used to finance the liquidated damages fund. Portions of the fund are forfeited if prescribed milestones are not met. The milestones are site control, permit application, engineering design, financial commitment, permit receipt, begin construction, and begin operation. Extensions of the operation deadline can be purchased through the payment of an extension fee into the liquidated damages fund.

VII. COLORADO

OVERVIEW

Status

Public Service Company of Colorado (PSCo) proposed a competitive bidding system for QFs in January 1988.[10] That proposal is described herein. The proposal was accepted by the state, with moderate change, but bidding has not yet been implemented.

Approach

Operating and planning needs are reflected in the bidding system through the categorization of suppliers and a bid scoring system.

Five categories called Electric Supply Groups (ESG) were created. This categorization is important because it dictates both the extent of operational control to be required from a bidder and the avoided cost prices that would set a ceiling on the prices offered by that bidder.

In addition to being reflected in the creation of the five ESGs, operating and planning needs were given great influence in the scoring system used to evaluate bids. Out of 100 possible points, bid price was given a possible maximum score of 25 points. The remaining 75 points were distributed among operability, facility characteristics, fuel, contract term, and project management and finance.

Finally, a project fee was set and a limit was set on the proportion of system needs that could be satisfied by QFs. A $10 per kw project fee was paid by all bidders, refunded immediately to all losing bidders, and refunded to winning bidders over the first five years of operation. PSCo set at 20 percent the limit on the proportion of system needs that could be satisfied by QFs.

PSCo's PROPOSAL

Categorization

ESG 1 and 2 covered sales of only energy and neither was key to the bidding system. ESG 3, 4, and 5 covered sales of both energy and capacity and would be included in the bidding system.

- ESG 3 covers unscheduled sales of energy and capacity. Wind and solar projects were said to be likely to fall into this category. Maximum capacity prices would be set equal to the Inland Power Pool's Operating Reserve Deficiency Charge, and energy prices would be set at average system coal-fueled production cost.

- ESG 4 covers energy and capacity sales that could be scheduled by hour. Maximum prices would be set according to prices for long-term, firm unit-contingent capacity and energy in the Rocky Mountain regional power market, but could be no higher than ESG 5.

- ESG 5 covers energy and capacity sales that would be under Automatic Generation Control. Avoided cost prices would be set according to the cost that would be incurred if PSCo built a major new power plant.

PSCo concluded that 65 percent of its supply must come from ESG 5, the category requiring Automatic Generation Control. For ESG 4 and ESG 3, the percentage of supply could be 28 and 7 percent respectively. PSCo concluded that this extent of operating control was required to match customer needs and system operating requirements.

Scoring System

A total of 100 points were distributed over six scoring factors. Within each factor the points given to a particular bid were based on the judgment of PSCo.

- Operability has a maximum score of 20 points. Examples of the factors to be considered are the nature of dispatchability offered and expected availability.

- Facility Characteristics have a maximum score of 15 points. Examples of the factors to be considered are the size of the project, the technology, and the location of the project with respect to transmission and distribution.

- Cost has a maximum score of 25 points.

- Fuel has a maximum score of 20 points. Examples of factors to be considered are fuel supply location and fuel transportation method.

- Contract Term has a maximum score of 15 points. A 30 year term is preferred, shorter terms will receive fewer points.

- Project Management and Finance have a maximum score of 5 points. Examples of the factors to be considered are the project experience of the bidders and the expected financeability of the project.

END NOTES

[1]Request For Proposals From Qualifying Cogeneration and Small Power Production Facilities (Boston: Boston Edison, 15 January 1987).

[2]Cogeneration/Small Power Production Request For Proposal (Augusta: Central Maine Power Company, 14 September 1984).

[3]Cogeneration/Small Power Production Request For Proposal (Augusta: Central Maine Power Company, 2 June 1987).

[4]Cogeneration and Small Power Production: Energy Alternatives for Maine's Future (Augusta: Central Maine Power Company, 1988), p. 15.

[5]Decision 86-07-004 (San Francisco: California Public Utilities Commission, 2 July 1986), p. 74.

[6]Request For Proposals For Power Purchases: 1988 Solicitation March 1, 1988 (Richmond: Virginia Electric & Power Company, 1 March 1988).

[7]"Follow-Up Bids Cut Va. Power's 27,000-MW Draw to 14,000 MW," Electric Utility Week, 20 June 1988, p. 19.

[8]"Va. Power Selects 2,041 MW, Mulls Another Solicitation, Own Plants," Electric Utility Week, 17 October 1988, p. 1.

[9]Proposed Integrated Supply Side and Demand Side Bidding Program (Pearl River, NY: Orange & Rockland Utilities, Inc., 1 October 1988).

[10]William J. Martin and Joe D. Heckendorn, Direct Testimony in Application No. 38771 (Denver: Public Service Company of Colorado, 29 January 1988).